

**Response of  
Wisconsin Power and Light Company  
to  
The Public Service Commission of Wisconsin  
Data Request No. 3.07**

Docket Number: 05-CE-137  
Date of Request: March 11, 2009  
Information Requested By: Ken Detmer  
Date Responded: March 30, 2009  
Author: Jeff Knier  
Author's Title: Project Director CACP  
Author's Telephone No.: (608) 458-4866  
Witness: (If other than Author)

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**Data Request No. 3.07:**

Follow-up to Question 1.12: p. 1, par. 3: Provide a copy of the independent engineering assessment referenced in which the SCR is the only feasible option toward meeting Phase II of RACT controls.

**Response:**

URS Washington Division (formerly "Washington Group International") was contracted by WPL to conduct an assessment of possible air pollution control equipment installed on WPL's operating fleet in order to reduce emissions in accordance with various regulatory requirements (2007). The study considered NOx control technologies as described in Section 6 of the CA document, including SNCR, RRI, Hybrid SCR, and full-size SCR at the Edgewater Generating Station. Table 7, included in Section 6 of the CA document, and was generated as a result of the URS Washington Division assessment.

Attachment 3.07 is URS Washington Division's engineering assessment of the WPL fleet, and in part discusses the technologies and the projected removal efficiencies that were considered as options for compliance of NOx rules. WPL utilized this engineering assessment to evaluate control technologies at the Edgewater facility and concluded, as stated in Section 6 of the Application, that the SCR technology is the desired technology for lowering NOx emissions at Edgewater 5.

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April 23, 2007

Mr. William Holewinski  
Project Director – Clean Air Compliance Program  
Alliant Energy  
4902 North Biltmore Lane  
Madison, WI 53718-2148

Job No.: 28958  
Letter No.: 2007-WA-181  
Response Req'd.: Yes  
File No.: 2.1; 5.2

**Subject: Alliant Energy Clean Air Compliance Program  
Compliance Model Report (Draft)  
Wisconsin Power & Light Fleet**  
Ref: 1. Letter 2007-WA-106 dated 3/15/07  
2. Letter 2007-WA-132 dated 4/4/07

Dear Bill:

Attached for your review are eight (8) copies of the draft CACP Compliance Model Report for the Wisconsin Power & Light fleet. Please note that the technology solutions presented herein were previously provided per the Reference Letter 1, with only one change on the NOx removal technology for Nelson Dewey unit 2. Also, the cash flow data for each technology has not been included in this report (generic data was previously provided via Reference Letter 2). Cash flow data, for the selected technologies by plant, will be provided in the format requested by AE in each of the PD Reports.

If you have any questions or comments regarding this transmittal, please contact Bill Lam or the undersigned.

Very truly yours,

A handwritten signature in black ink, appearing to read 'Anthony J. Cirillo'.

Anthony J. Cirillo  
Program Director

Attachments



**FOSSIL GENERATION  
ENVIRONMENTAL PROJECTS**

**Clean Air Compliance Program**

**Project Number 28958**

**CACP Compliance Study  
Wisconsin Power & Light  
Preliminary Report**

PREPARED FOR



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Revision: B

Status: Preliminary

Date: April 20, 2007



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**REVISION PAGE**

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Ira S. Brodsky	<i>I. Brodsky</i>	<i>4/24/07</i>	<i>4/24/07</i>
Prepared by	<i>Zhen J. Jia</i>	Date <i>4/24/07</i>	Approved by PEM <i>[Signature]</i> Issue Date
Checked by		Date	Approved by PM Date

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Prelim	B	04/20/07	ISB	All	For Client Review

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- B – SO<sub>2</sub> Control Technology Descriptions
- C – NO<sub>x</sub> Control Technology Descriptions
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- E – IECCOST Model Run Summaries by Plant
- F – Client/Vendor Cost Information
- G – Compliance Model Run Summaries
- H – General Arrangements of SCR and FGD Technologies, by Plant

**LIST OF REFERENCE DOCUMENTS**

- Alliant Energy Emissions Model (V3\_24\_06)
- Fuel Assessment Study
- Unit Technical Data Sheets
- IECCOST Model Technology Application Matrix

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## 1.0 EXECUTIVE SUMMARY

### 1.1 Introduction

Alliant Energy has prepared a System Emissions Model through year 2023 to plan staged implementation of SO<sub>2</sub>, NO<sub>x</sub> and Mercury removal technologies for each of their fleets (Iowa: Interstate Power and Light; Wisconsin: Wisconsin Power and Light) to comply with the Clean Air Interstate Rules (CAIR) and Clean Air Mercury Rules (CAMR). Washington Group International's CACP Multipollutant Compliance Model was used to determine the least (present worth) cost selection of pollution control technologies to be applied to select coal-fired units in each fleet, and to serve as an independent check against Alliant's Emissions Model and implementation plan. The program's stated compliance schedule is shown in the table, below:

**Table 1-1**  
Program Compliance Schedule

Pollutant	Intermediate Target Year	Final Target Year
NO <sub>x</sub>	2009	2015
SO <sub>2</sub>	2010	2015
Hg	2010	2018

This report is specific to the Wisconsin Power and Light (WPL) fleet. Alliant has selected the following coal-fired units to be candidates for the addition of pollution control systems:

- Columbia 1
- Columbia 2
- Edgewater 4
- Edgewater 5
- Nelson Dewey 1
- Nelson Dewey 2

All other units within the Wisconsin fleet, including new units and retirements, were treated as "non-controlled" with unit base emissions as inputs to the model. The non-control units include:

- Blackhawk 3&4
- Edgewater 3
- Neenah Energy Facility 1&2
- Rock River 1,2, 3, 5, 6
- Sheepskin 1
- South Fond Du Lac 1,2,3,4
- Sheboygan Falls (New)

As Alliant has partial ownership of several units in the fleet, the emissions model solution was optimized for least-cost system-wide considering their share, only.



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## 1.2 Study Approach

The SO<sub>2</sub> and NO<sub>x</sub> control technologies considered are listed in Table 1-2. These technologies are considered proven and are commercially available. There is limited data for many mercury technologies listed in Table 1-2, but all are commercially available and are considered feasible for use with the PRB fuels burned by WPL, either through operating experience or pilot testing on smaller units. The model considers synergistic effects between technologies and co-benefits for mercury removal. Some technologies that are in the planning stages were incorporated into the model as part of a solution, wherein the recommendation will cover going forward with the implementation or switching technologies or time frame.

**Table 1-2**  
Pre-Screened Technologies

Pollutant	Technologies
NO <sub>x</sub>	Smartburn® Low-Nox Burners – Separated Overfire Air Rich Reagent Injection (RRI) Selective Non-Catalytic Reduction (SNCR) – Urea Reagent Selective Catalytic Reduction (SCR) – Ammonia Reagent Hybrid SCR (HYB-SCR)– SNCR followed by in-duct SCR
SO <sub>2</sub>	Limestone Forced Oxidation (LSFO)– Wallboard Quality Gypsum Semi-Dry Lime Spray Dryer (LSD) – Landfill Disposal Semi-Dry Circulating Fluidized Bed Scrubber (CFB) – Landfill Disposal
Hg	Brominated fuel combustion additives (BCA) Toxecon (TOX-I) Toxecon II (TOX-II) Brominated activated carbon injection (ACI) Chemical additives to LSFO systems SCR mercury oxidation catalyst in conjunction with LSFO systems

Washington Group International (Washington Group) prepared capital and O&M costs for each of the above technologies, at each of the six candidate units considered for this study, through the use of the EPRI IECCOST model. This model was supplemented with material takeoffs and input from equipment suppliers. In general, the costs for pollution control were expressed in terms of levelized annual costs, spread over the economic life, starting in 2009, the first date of compliance.

The problem of selecting the least-cost combination of control technologies is the complexity due to the sheer number of possible combinations. The selection process is further complicated by the fact that synergistic effects between technologies lead to different mercury removal efficiencies depending on which NO<sub>x</sub> and SO<sub>2</sub> technologies are installed at a particular unit. Washington Group employed a very large Excel spreadsheet, in conjunction with using Premium Solver®, to minimize the system-wide cost. This was done while satisfying the constraints on SO<sub>2</sub>, NO<sub>x</sub>, and mercury emissions and Alliant Energy's desire to minimize the purchase/sale of allowances over the course of the economic life (allowance neutral position).

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The Excel/Solver model is employed in two steps to yield a solution. The first run narrows the universe of potential SO<sub>2</sub> and NOx controls to one allowable set of least-cost technologies per unit at the final target year (2015/2018). Mercury technologies are not selected in the first run in order to preclude those relatively low capital cost technologies, with limited operating histories, from driving the selection of the SO<sub>2</sub> and NOx control technologies. The second run selects which SO<sub>2</sub>, NOx and mercury technologies, including co-benefits, to install prior to the 2009/10 intermediate target year in order to achieve the required emissions reduction. The second run is the final solution and may eliminate the requirement for installing technologies at one or more units because early implementation would allow buildup of credits to be sold in lieu of implementation during the economic life of the model. As noted, the solution is the least-cost set of technologies and installation schedule required to minimize buying and selling of credits over the economic life (20 years).

The economic life of the model affects both the choice of technologies and implementation years as O&M costs become more influential the longer the economic life. O&M costs, such as loss of ash sales and disposal, may drive the solution more than capital costs, given sufficient model life. A sensitivity analyses was performed to see the impact of varying economic life (20/25/35 years) on technology selection.

### 1.3 Results

#### 1.3.1

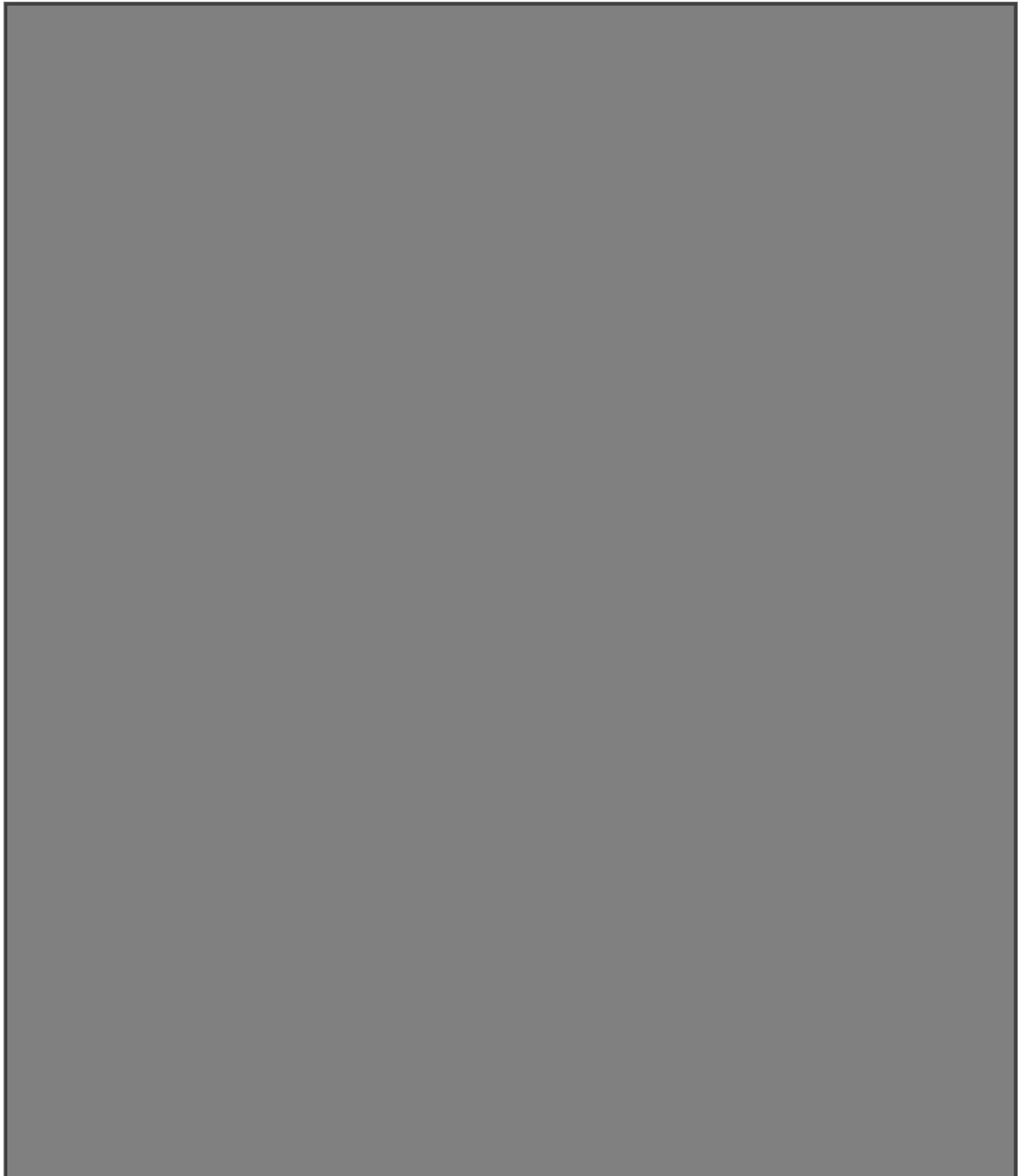





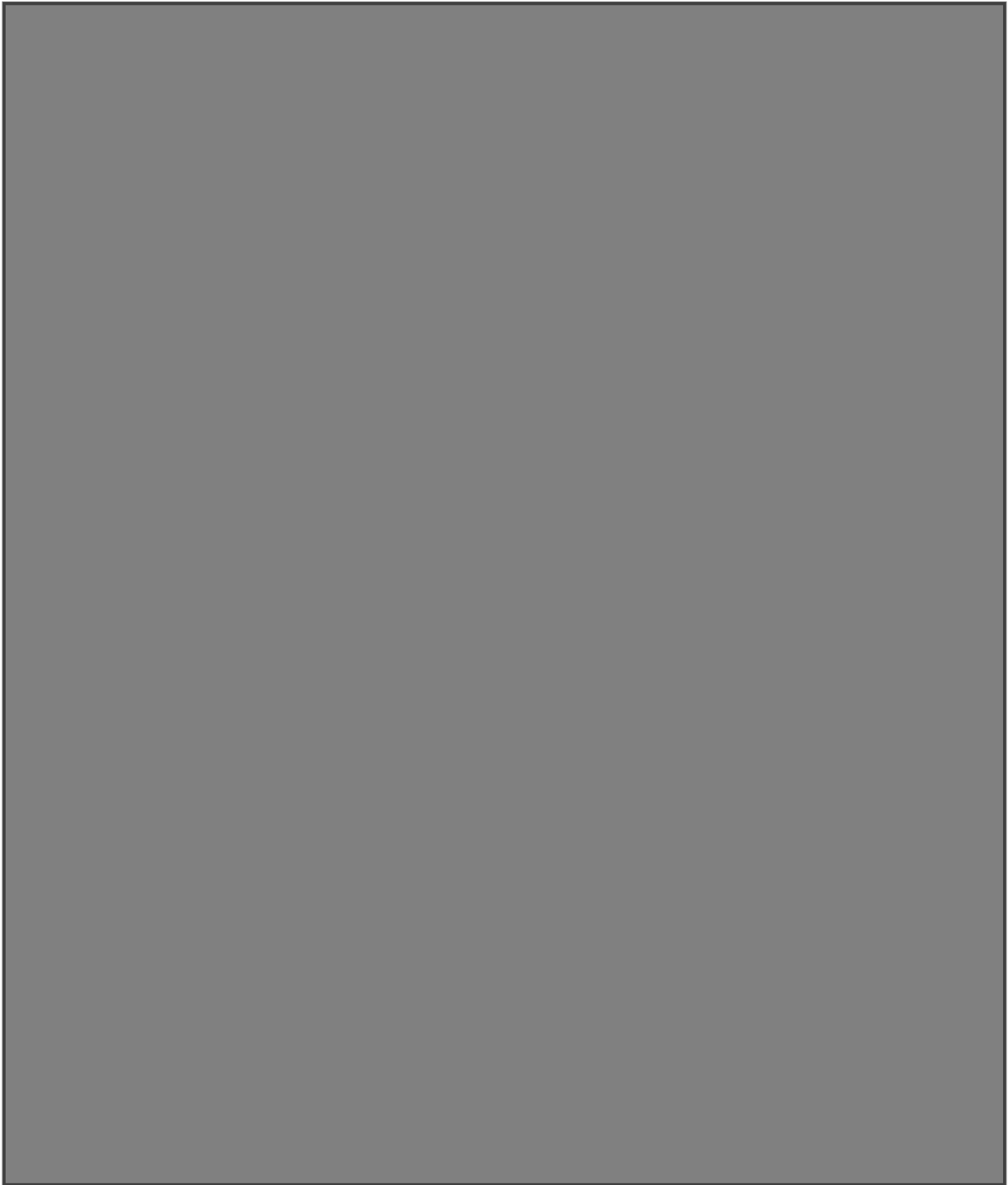
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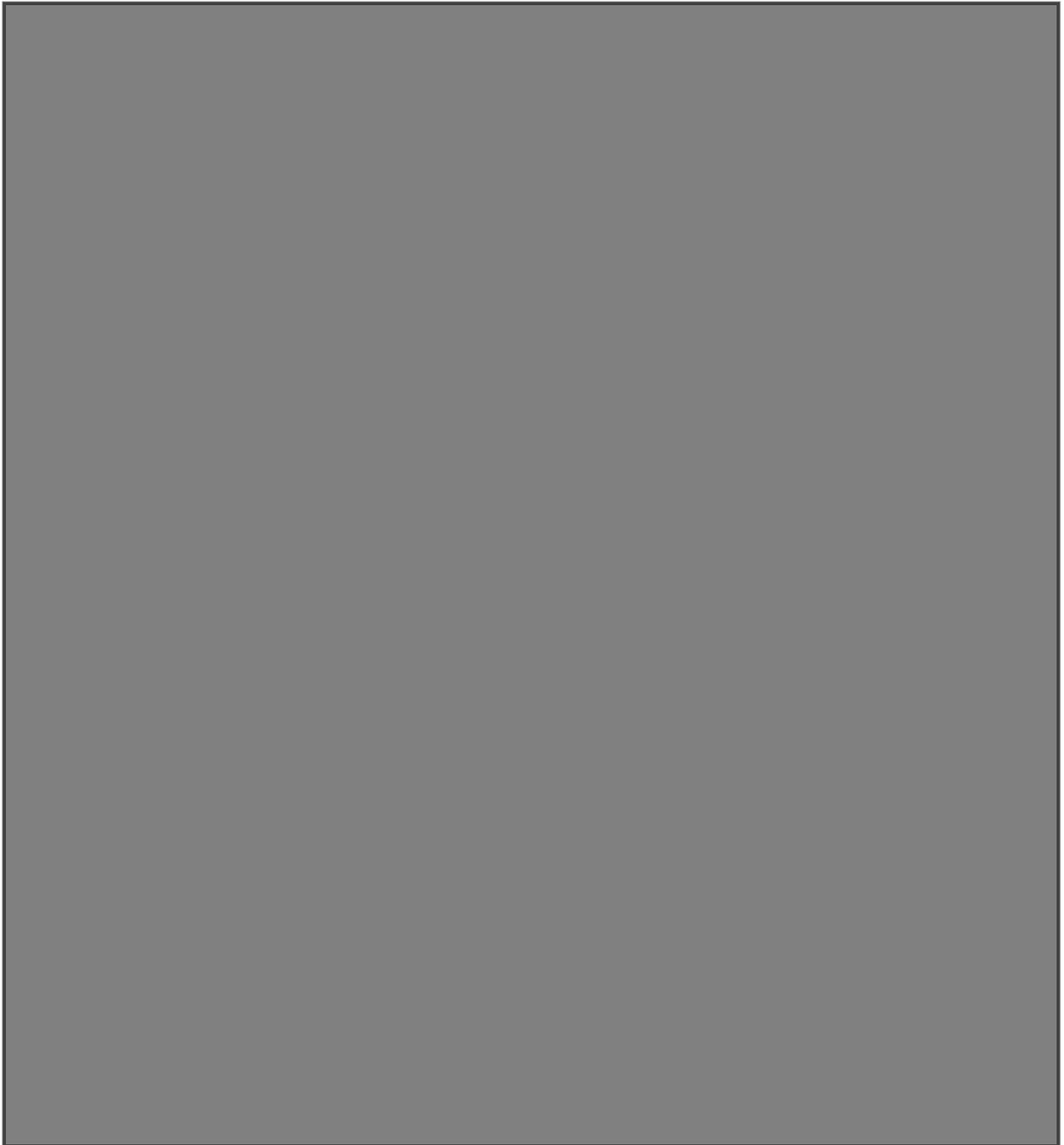




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### 1.3.3 RACT/BART Solution

A solution for the Wisconsin RACT/BART requirements in 2013 was not produced per Alliant's request that they be put on Hold until the requirements were clarified. However, early implementation of the late compliance date technologies (Table 1-3) by 2013 will likely meet all RACT/BART requirements.

### 1.3.4 Sensitivity Analysis

The baseline first run (late compliance) narrows the universe of potential SO<sub>2</sub> and NO<sub>x</sub> technologies to one set for each unit in the fleet. The second (early compliance) solution is a subset of the first in that implementation of one or more SO<sub>2</sub> and NO<sub>x</sub> control technologies may potentially be eliminated due to the early buildup of credits. Therefore, the first run solution was used as the base against which all sensitivity runs were compared. Sensitivity results include potential shifts in technologies as well as changes in net present value and total plant cost for the fleet.


The sensitivity runs, presented in Section 6.0, show that the compliance solution is generally insensitive to changes in both reagent and disposal costs.

The solution is also insensitive to 125% of the baseline allowance pricing (Note: Allowance purchases are minimized). However, when the cost of allowances decrease to 75% of the baseline (-25%), there is a shift to some less efficient technologies since purchases of less costly credits may be less costly than implementation of more efficient technologies.

The greatest shift in technologies was found to be a result of lengthening the economic life of the model to 35 years. This is explained by the fact that the longer the economic life of the model, the more O&M costs tend to overwhelm the initial capital cost.

## 1.4 Validation of Alliant Energy's Emissions Model

The main purpose of this CACP compliance model study was to independently validate Alliant Energy's technology selections for the WPL units. A comparison of the technology selections by the models is presented in Table 1-6, below. It can be seen that AE's model was validated in that there is a good correlation between the technologies selected by both models. The selection of higher-efficiency technologies by the CACP model, and implementation for units not selected by the AE model, are caused by the requirement that the CACP model be, on average, as close to allowance neutral as possible over the economic life.

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**Table 1-6**

Wisconsin Power & Light  
Comparison of CACP Technology Selection with AE Compliance Model

Unit	CACP TECHNOLOGY SELECTION (2015/2018)			AE MODEL TECHNOLOGY SELECTION		
	SO <sub>2</sub>	NO <sub>x</sub>	Hg	SO <sub>2</sub>	NO <sub>x</sub>	Hg
Columbia 1	LSFO	SCR	BCA+ACI	Dry FGD	SCR	Chemical Injection
Columbia 2	LSFO	SCR	BCA	Dry FGD	SCR	Chemical Injection + ACI
Edgewater 4	LSFO	SNCR	BCA	None	RRI + SCR	None
Edgewater 5	LSFO	HYB-SCR	BCA	None	SCR	Sorbent Injection.
Nelson Dewey 1	LSFO	RRI	BCA	Dry FGD	RRI	None
Nelson Dewey 2	LSFO	RRI	BCA	Dry FGD	RRI	None

**CAUTION:**

The IECCOST model, as used for this study, has an inherent accuracy of  $\pm 30\%$  in predicting capital and PWRR costs. Since the model has been applied equally for all technologies across all units of the fleet, the errors in comparative costs are much smaller than the above figure.

However, based on current market conditions, absolute capital costs in the upper end of the range of accuracy should be anticipated.





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## 2.0 INTRODUCTION

### 2.1 Objective

Alliant Energy's emissions model, including allowances, was used by Washington Group to determine the least present worth cost selection of technologies that meets targeted emissions requirements while minimizing purchase or sales of allowances over the economic life of the model. All costs and emissions are presented as Alliant Energy's shares of partially-owned units. All total plant costs (total emission control system installed costs) are in 2006 dollars. All economic results are in 1/1/2009 dollars.

The study determined the optimum mix of technologies and their staging in two discrete steps:

- A. Determine which units should implement which technologies by the respective Final Target Years.
- B. Using the technologies determined in (a), above, determine which are to be implemented by the Initial Target Years to meet intermediate pollutant reduction goals.

The optimized solution will stage the recommended technologies among Alliant Energy's pre-selected control units for direct comparison with their System Emissions Model. The total costs for the optimized solutions extend through year 2029.

### 2.2 Study Approach

A study kick-off meeting was held at the Madison office of Alliant Energy. At the kickoff meeting, the goals of the study, the study methodology, expected deliverables, and schedule were reviewed to assure that all parties understood and agreed with the objectives. Prior to the meeting, Alliant Energy submitted their in-house compliance model for Washington Group's use in running the IECCOST and compliance models.

Following the kickoff meeting, Washington Group International visited each plant and Alliant Energy submitted design and operating information and economic factors for each control unit in the fleet to collect pertinent data that addressed the following design issues:

- Current emission levels and unit operating data.
- Future projects that may impact plant emissions.
- Available space for the emission control equipment.
- Roads, access, congestion and other retrofit factors that influence total retrofit costs.
- Existing duct configuration.
- Major underground structures.

Based upon the collected data, review of the Alliant Energy compliance model and subsequent discussions, Washington Group adjusted design fuels and unit capacities to align the baseline emissions with the AE compliance model. Current fuels were adjusted to achieve conservative capital costs of FGD systems based on a combination of lower heating values and higher sulfur levels in the fuel. Capital costs for NOx and Mercury control systems and O&M costs for all abatement equipment, however, are based on AE's actual emissions derived from their compliance model and plant data.

Washington Group then developed a Design Basis Document to establish a consistent basis for the study. This document was subsequently reviewed by AE, updated accordingly, and is reflected throughout this



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report. Inputs used by IECCOST and the compliance model were included in the Design Basis Document and are shown in Appendix A of this report.

The general sequence of the study was:

- A. Selecting fuel composition and adjusting unit capacity factors to obtain uncontrolled emissions and unit heat rate consistent with those used by Alliant in their model. This step was required to allow IECCOST to conservatively calculate capital costs of the SO<sub>2</sub> technologies consistent with the higher range of sulfur content in the present fuels.
- B. Alliant Energy economic information for each unit and allowance pricing, by year, were gathered and incorporated into the design basis document. They are included in the body and Appendix A of this report.
- C. The IECCOST model was run for each unit to determine the capital costs and fixed O&M costs of each control technology in 2006 dollars. Results are presented in Appendix E.
- D. For those technologies not pre-programmed into IECCOST, capital costs were determined from independent suppliers and in-house information. In general, these technologies include some mercury control options and chemical additive systems. This information is presented in Appendix F.
- E. Capital costs for the technologies for each unit, determined above, were input into the Washington Group compliance model. Alliant's emissions and required reductions from current fuels were also input into the compliance model so that O&M costs for the solution accurately reflect Alliant's requirements.
- F. The first baseline run was made to determine the lowest cost mix of control technologies for each unit required to meet the total fleet emissions requirements at final implementation in years 2015 (NO<sub>x</sub>, SO<sub>2</sub>) and 2018 (Hg). If the required emissions reduction could not be met, allowance purchases were incorporated into the solution.
- G. A series of test runs was conducted to check that the complex model gave repeatable and realistic solutions. At this time, the model was also checked for sensitivity and repeatability as to the proper handling of Alliant Energy's shares in the overall solution. Initial results were presented to Alliant and adjustments were made to the constraints and pre-selected technology mix according to their requirements.
- H. The first baseline was re-run with the above changes to obtain the starting SO<sub>2</sub> and NO<sub>x</sub> technology mix for each unit and the base cost of the solution for comparison with all future runs.
- I. The second baseline run was made to determine the lowest cost mix of technologies for each unit to meet the fleet emissions requirements in years 2009 (NO<sub>x</sub>) and 2010 (SO<sub>2</sub>, Hg). SO<sub>2</sub> and NO<sub>x</sub> control technologies were limited to those selected by the first run. The mercury control solution included co-benefits of the selected NO<sub>x</sub> and SO<sub>2</sub> technologies. This run is the optimized least-cost solution.
- J. A series of sensitivities were run to determine if the initial selection of technologies obtained in the first baseline run of 2015/2018 would change with +/- changes in parameters (allowance price, consumable costs, etc.). The Net Present Value of capital, O&M, and allowance cost/sale, were included in the sensitivity analyses to provide an estimate of the overall cost impact, even if there were no changes in selected technologies.



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### 3.0 OPTIMIZATION MODEL DESIGN

#### 3.1 Methodology and Construction

The Multipollutant Compliance Model evaluates the costs of combinations of FGD, NOx, and mercury control processes for multiple Alliant units in Wisconsin and Iowa to determine the most cost-effective mix of the control processes for the fleet of generating units in each state. The Model is based on a comprehensive spreadsheet, which uses mixed integer routines and Premium Solver Platform to assess over 10<sup>50</sup> possible combinations of emission control processes to determine the mix of technologies that meets emission constraints and results in the lowest present worth of revenue requirements (PWRR). Premium Solver uses statistical routines to assess all feasible combinations of emission control to converge on the solution with the lowest PWRR that meets the emission constraints for NOx, SO<sub>2</sub>, and mercury.

The Model has the following features:

- A. Starts with the uncontrolled emissions, unit size, heat rate, and capacity factor to determine the uncontrolled emissions for each unit
- B. Simultaneously evaluates voluminous combinations of FGD, NOx and Mercury control processes for the fleet.
- C. Uses outputs derived from EPRI's IECCOST program to provide the unit-specific estimates of capital costs, operating costs, maintenance costs, and consumable quantities for the NOx, SO<sub>2</sub>, and mercury emission control systems. The Model can substitute unit-specific quotes from third parties or in-house data for the IECCOST estimates.
- D. Allows a mix of NOx control, SO<sub>2</sub> control, and Hg control on one unit; no-NOx control, SO<sub>2</sub> control, and Hg control on another unit; one NOx control, no-SO<sub>2</sub> control, and Hg control on another unit or any combination or mix of emission control processes for the fleet of units that results in the lowest PWRR while meeting emission requirements.
- E. Evaluates individual and combinations of the SO<sub>2</sub>, NOx and mercury processes defined in Table 1-2 and "selects" the mix of processes that meet emission limits or required reductions at lowest cost. The model allows for one SO<sub>2</sub> process, up to three NOx processes, and up to three mercury processes on a unit.
- F. Takes into account emission control systems that have been or will be installed by Alliant prior to 2008. It does not include the costs of these systems and the Model starts with the outlet emissions emitted for the unit configuration, as it exists prior to retrofit of new or additional emission controls.
- G. Uses the capital costs, O&M costs, consumable quantities and resulting consumable costs to determine the present worth of NOx, SO<sub>2</sub> and mercury emission control options.
- H. Determines year-by-year costs, heat input, uncontrolled emissions, and controlled emissions for each unit for each year over the economic life of the study.
- I. Allows for the sale or purchase of NOx, SO<sub>2</sub>, or Hg allowances in combination with varying degrees of control and/or processes that result in the most cost-effective mix of emission control processes and allowances for the fleet.
- J. If NOx and/or SO<sub>2</sub> removal processes are selected for a unit, accounts for co-benefits of mercury removal by these processes.
- K. When the NOx control for a unit involves multiple processes, the removal efficiency of the second process (or third process if selected) is reduced due to the lower NOx emission "entering" the subsequent process. The same principal is observed for a second mercury process if selected.



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### 3.2 General Requirements

- A. The model will independently evaluate each of the designated units in a fleet. Therefore plants with multiple units (e.g. Columbia 1, 2) may have any technology or combination of technologies in the optimized solution for each unit and any or all pollutants.
- B. Model economic evaluation: Start Date: 2009; End Date: 2029.
- C. The cost of each suitable candidate technology for each unit was derived from IECCOST and was manually transferred to the Compliance Model. Wherever applicable, inputs to the Wisconsin and Iowa Models are the same. Where the standard IECCOST model does not include the candidate technologies, the costs were supplemented by in-house estimates and supplier input, if available.
- D. The model determined the Present Worth levelized costs as part of the solution. The Alliant Emissions year represents a full year of operation. Therefore, start year of all control technologies were by December 31 of the previous year.
- E. For SO<sub>2</sub> control systems, capital costs were determined by running IECCOST for the design high sulfur/low HHV fuel listed in Appendix A. The capital cost is based on the full-size unit. Alliant's ownership percentage is then applied to this cost in the Compliance Model. Variable and fixed O&M costs are based on the emissions allowances and limits determined from Alliant Energy's in-house model.

### 3.3 Target Emissions

- A. Baseline emissions for each unit, by year, are given in Alliant Energy's Emissions model and a summary has been provided per Appendix A.
- B. The optimal model results would obtain a least cost solution over the 20-year economic life of the model without purchasing or selling credits. In practice, however, the emission removal efficiencies of the alternate control options and nonlinear programming algorithms require a narrow "target" band to converge to a solution. The band to allow convergence of a run to a solution has been set as narrow as practical to disallow net purchases of credits yet allow a small amount of credits (0-10% of total emissions for the SO<sub>2</sub> and NO<sub>x</sub> technology selection runs; 0-5% for the final solution) to be sold over the life of the model. The target band was expanded, however, if required to obtain a solution for all runs.
- C. In addition, each individual unit will meet individual permit limits, if such exists. The base solution was obtained for the single most stringent case for each unit and/or the fleet of units. The following cases were run as part of the sensitivity analysis of the solution:
  - CAIR, only (Base Scenario).
  - CAIR + RACT.
  - CAIR+RACT+BART.

Where:

CAIR = "Clean Air Interstate Rule" for SO<sub>2</sub> and NO<sub>x</sub> Emissions limitations.

RACT = "Reasonably Available Control Technology", required on existing sources in areas that are not meeting national ambient air quality standards (i.e., non-attainment areas).

BART = "Best Available Retrofit Technology" required for existing emission sources impacting visibility at Class I areas under Regional Haze rule.



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- D. Per Alliant Energy's requirements, the following Wisconsin units will be considered for RACT and BART:

**Table 3-1**

WPL RACT / BART Requirements

UNITS	RACT (NO <sub>x</sub> )		BART	
	2009	2013	NO <sub>x</sub> (2013)	SO <sub>2</sub> (2013)
Edgewater 4	0.15 lb/MMBtu	0.10 lb/MMBtu	0.10 lb/MMBtu	95% Removal or 0.15 lb/MMBtu
Edgewater 5	0.15 lb/MMBtu	0.10 lb/MMBtu	N/A	N/A
Columbia 1	N/A	N/A	0.15 lb/MMBtu	95% Removal or 0.15 lb/MMBtu
Columbia 2	N/A	N/A	0.15 lb/MMBtu	95% Removal or 0.15 lb/MMBtu
Nelson Dewey 2	N/A	N/A	0.10 lb/MMBtu	95% Removal or 0.15 lb/MMBtu

- E. Edgewater 4 and 5 must meet  $\leq 0.07$  lb/MMBtu NO<sub>x</sub> emissions in order for the Edgewater 3, 4, and 5 meet the 2013 requirements listed in Table 3-1.
- F. The following table is a summary of fleet-wide emissions targets, including CAIR and CAMR requirements, and required reductions for Intermediate and Final target years.

**Table 3-2**

Target Emissions and Reductions (AE Share)

Wisconsin Power & Light (WPL)

	NO <sub>x</sub> (ton/yr)			SO <sub>2</sub> (ton/yr)			Hg (lb/yr)		
	Base	2009	2015	Base	2010	2015	Base	2010	2018
Required Total Emissions [A]	<b>7,878</b>	7,318	6,146	<b>41,366</b>	18,205	12,744	<b>512</b>	347	140
Non-Control Unit Emissions-Existing [B]	<b>1,204</b>	1,204	1,276	<b>1,748</b>	1,748	1,575	<b>22</b>	22	18
Non-Control Unit Emissions-New [C]			782			949			74
Total Non-Control Unit Emissions [D]=[B+C]		1,204	2,058		1,748	2,524		22	92
Required Control Unit Emissions [E]=[A-D]	<b>6, 674</b>	6,114	3,908	<b>39,618</b>	16,457	10,220	<b>490</b>	325	48
Required Control Unit Reduction [Base-E]		560	2,766		23,161	29,398		165	442
Required %Reduction		8.4%	41.4%		58.5%	74.2%		33.7%	90.2%



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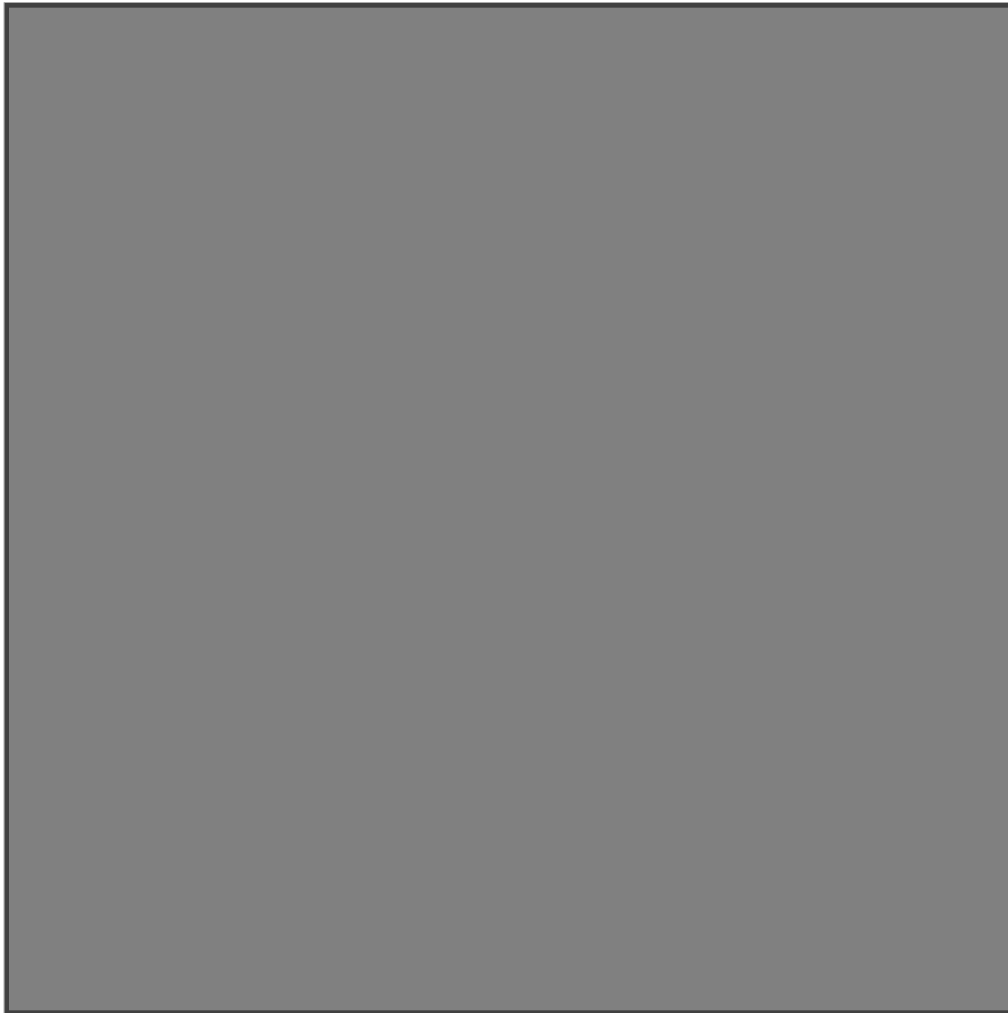
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### 3.4 Economic Factors

- A. Although most economic factors will be common to all units in the system, the model will have the capability to enter them independently for each unit. Refer to Appendix A, Summary of Inputs.
- B. The costs for O&M items are subject to variations at individual plant sites and inclusion of other chemicals for alternate technologies. They are also presented in Appendix A, Summary of Inputs.

### 3.5 Allowances

- A. Alliant Energy's Allocation of allowances varies each year according to their emissions model. Reference the Baseline Emissions and Capacity Factors in Appendix A.
- B. The value of the optimized solutions shall be tested for sensitivity to variations in the cost of allowances by varying the present worth of all allowances. Initial runs will be made at  $\pm 25\%$ . If the solution is sensitive to a 25% variance in allowance costs, additional runs shall produce five-point sensitivity curves (-25%, -10%, Baseline, +10%, +25%).
- C. The model shall use Allowance Pricing as predicted below:







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### 3.6 General Constraints

- A. There may be only zero or one SO<sub>2</sub> reduction technology per unit.
- B. Provisions were made for up to two (2) Hg removal technologies per unit to allow series implementation of one (1) pre-combustion and one (1) post-combustion technology. However, native capture and co-benefits with NO<sub>x</sub> and FGD technologies will be applied, even if no mercury-specific technology is used.
- C. Provisions were made for up to three (3) NO<sub>x</sub> removal technologies per unit to allow staged implementation of Smart-Burn (LNB) plus two (2) post-combustion controls. Implementation of two (2) post combustion controls are to be limited to a combination of one (1) SNCR + one (1) SCR technology.
- D. All units were screened for their suitability to incorporate each control technology. The Model was constrained to consider only technologies that are suitable for the unit.
- E. Where hot-side ESP's exist (i.e. Columbia 1), the Model did not consider converting to cold-side ESP's for technology screening and removal efficiencies.
- F. Technologies to be implemented for each unit in intermediate years are to be limited either to none or to the technology selected for the Final Target Year solution.
- G. Specific constraints for each pollutant and combination of technologies are listed in Section 4.



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#### 4.0 CANDIDATE TECHNOLOGIES

Alliant Energy provided the following candidate technologies for use in the compliance model:

**Table 4-1**

Pre-Screened Candidate Technologies

SO <sub>2</sub>	NO <sub>x</sub>	Hg
Dry Scrubbing	SmartBurn (Low-NO <sub>x</sub> Burners + Overfired Air)	Fixed Structure Sorbents
Wet Scrubbing	Selective Non-Catalytic Reduction (SNCR)	Oxidation through SCR catalyst
	Selective Catalytic Reduction (SCR)	Sorbent Injection (ACI, BCI)
	Hybrid SNCR+SCR	Toxecon I
	Reagent Rich Injection (RRI)	Toxecon II
		Co-benefit and Native Removal

The above, and additional technologies proposed by Washington Group, have been screened for suitability and nominal removal efficiencies, both alone and in series. The technologies incorporated in the model are presented in the Referenced IECCOST Model Technology Application Matrix and the following sections:

#### 4.1 SO<sub>2</sub> Control Technologies

- A. Selection of SO<sub>2</sub> control technologies and their removal efficiencies are to suitable for the average PRB fuel presently burned throughout the system.
- B. The following technologies and removal efficiencies shall be the candidates for all units unless site specifics precludes their implementation:

**Table 4-2**

Flue Gas Desulfurization Technologies

FGD Technology	Removal Efficiency
Lime Spray Dryer (LSD)	92%
Circulating Fluidized Bed (CFB)	94%
Wet Limestone – Forced Oxidation (LSFO) (current fuel)	* 95%
Wet Limestone – Forced Oxidation (LSFO) (Rosebud fuel)	* 97%

\* LSFO Removal Efficiency is based on PRB fuels and a reasonably achievable outlet SO<sub>2</sub> emission of 20 ppm.





Descriptions of the technologies are included in the Appendix B.

- C. For units burning higher-sulfur Rosebud fuel, the assumed removal efficiency for LSFO systems is assumed to be 97%.
- D. Both commercial-grade and disposal-grade gypsum are to be considered as the LSFO byproduct, subject to environmental regulations and permits that may preclude unwashed gypsum disposal for specific units. Therefore, two LSFO alternatives are to be considered for each unit.
- E. Where a single FGD module can serve multiple units (i.e. LSFO and CFB), alternative cases for one module per unit and a common module for multiple units will be considered for each applicable plant. The compliance model will be run for the individual units and costs will be developed separately for the alternate scenario should multiple units be selected. In this case, the technology must have been proven at the combined total capacity and a minimum 5:1 turndown capability.
- F. The Model will be used to determine if Columbia 1, Columbia 2 should install FGD systems. When determined, the selected technologies and their implementation years shall be constraints on the optimized solution.
- G. Pending review of plant-specific arrangements to allow for FGD systems to be installed upstream of existing fly ash collection systems, CFB and LSD fabric filters are assumed to collect reaction products, only. Therefore, existing fly ash sales are assumed not to be impacted by installation of any FGD system.

#### 4.2 NOx Control Technologies

- A. Selection of NO<sub>x</sub> control technologies and their removal efficiencies are to be suitable for the PRB fuels presently burned throughout the system.
- B. The following stand-alone NO<sub>x</sub> technologies and removal efficiencies are based on typical PRB fuels and shall be the candidates for all units unless site specifics preclude their implementation. Additional commercially available technologies, if implemented in the IECCOST program, can be considered.

**Table 4-3**

NO<sub>x</sub> Reduction Technologies  
 Stand-Alone Removal Efficiencies

NO <sub>x</sub> Reduction Technology	Stand-alone Efficiency	Notes
Smart-Burn Low NO <sub>x</sub> Burner (LNB)	30%	Includes Separated Overfire Air (SOFA). Efficiency is dependent on pre-control emissions and predicted effectiveness provided by AE.
Rich Reagent Injection (RRI)	30%	
Urea SNCR	25%	
Hybrid SCR	55%	SNCR followed by in-duct SCR
Full-size SCR	90%	Ammonia reagent



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- Descriptions of the technologies are included in Appendix C.
- C. More than one NO<sub>x</sub> reduction technology can be placed in series at any unit. The total will not exceed three (3) technologies for any unit.
  - D. Where appropriate, urea reagent will be used for SNCR and Hybrid SCR's. Ammonia reagent will be used for full-sized SCR's and shall be limited to 19% solution.
  - E. The reasonably achievable NO<sub>x</sub> emission level is expected to be 0.06 lb/MMBtu. No single or multiple technologies in service, with the exception of full-size SCR's will be allowed to emit NO<sub>x</sub> below this level. The floor is lowered to 0.04 lb/MMBtu when full-sized SCR's are installed. When more than one NO<sub>x</sub> removal technology is placed in series, efficiencies shall be back calculated from the baseline lb/MMBtu to a final emission not less than 0.04 lb/MMBtu. Therefore, corrections to downstream technology removal efficiencies will be adjusted (downward) to account for the lower emissions from the upstream technology.
  - F. RRI will be considered only for cyclone boilers (i.e. Edgewater 4, Nelson Dewey 1&2, Sutherland 3).
  - G. Smart Burn LNB+SOFA technology will be considered only for PC boilers.
  - H. Hybrid SCR removal efficiency is based on a combined high-efficiency SNCR plus low-efficiency SCR. For purposes of this study it will be considered a single technology because of inherent differences in the reagent feed systems between a combined system and two independent systems. Implementation of a Hybrid SCR precludes the use of separate SNCR, SCR and RRI technologies for that unit.
  - I. The following removal efficiencies shall be used for multiple technologies in series:

**Table 4-4**

NO<sub>x</sub> Reduction Technologies  
Combined Removal Efficiencies

NO <sub>x</sub> Reduction Technologies	Maximum Combined Removal Efficiency
Smart-Burn + SNCR	50%
Smart-Burn +RRI	50%
Smart-Burn + RRI + SCR	90%
Smart-Burn + SNCR + SCR	90%
Smart-Burn + Hybrid SCR	65%
SNCR + SCR	90%

#### 4.3 Mercury Control Technologies

- A. Co-benefits with FGD systems shall be considered only for the specific FGD systems that are in the model solution. Therefore, mercury removal requirements will not drive the FGD solution.
- B. The Compliance Model will use the baseline mercury emissions generated by the Alliant Energy model. Native mercury capture for existing systems are considered to be part of the baseline emissions. Refer to Appendix A.



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- C. Pending review of environmental regulations for the state, mercury controls will not be considered for Units <100 MW (i.e. Edgewater 3) because of their relatively small size compared to the fleet capacity.
- D. The design basis for mercury emissions shall be 70% elemental + 30% oxidized. An additional 15% increase in oxidation of the mercury is assumed when an SCR is also selected (34.5% total mercury is oxidized at the SCR outlet).
- E. Hot vs. cold side ESP's will be considered in the suitability of removal technologies and their expected efficiencies. An additional 15% increase in oxidation of the mercury is assumed when an SCR is also selected (34.5% of total mercury is oxidized at SCR outlet.)
- F. The maximum total mercury removal efficiency for multiple technologies and co-benefits shall not exceed 90%. Note that, due to the lack of data, there is no "reasonably achievable limit" specified for mercury emissions.
- G. The following technologies shall be reviewed for demonstrated technical capability with PRB fuels, applicability to specific units, and commercial availability. Additional technologies may be added, subject to above constraints and implementation within the IECCOST model.

**Table 4-5**

Pre-Screened Mercury Reduction Technologies

Hg Reduction Technology	Notes
Fuel Additives (Halogenated Salts)	For purposes of this study, brominated compounds are assumed equivalent in efficiency to chlorinated compounds.
Fixed Adsorption Structures	MerCAP technology is eliminated from consideration as it has only been tested at the pilot scale.
Hg Oxidation by SCR Catalyst	For purposes of this study, it can be used only in conjunction with halogenated fuel additives and a downstream wet FGD system. Because of limited data SCR catalysts specific for enhanced mercury oxidation are considered experimental this time.
Sorbent injection	Each unique sorbent to be considered a separate technology.
Toxecon I	Activated Carbon injection followed by fabric filter
Toxecon II	Includes modification of existing ESP.
Wet FGD System Additives	In conjunction with LSFO, only.
Coal Blending	Not considered for the Alliant Fleets
Coal Pretreatment	Replacing PRB fuels with a proprietary, single-source fuel (e.g. K-Fuel) is not considered viable.
Oxidizing Chemicals	Eliminated from consideration, since it has not been tested on PRB boilers.

- H. Mercury capture by treating the PRB fuel with halogen salts prior to combustion are assumed to be equivalent to capture by technologies with bituminous fuels.
- I. LSD and CFB dry FGD systems are assumed to have equivalent native mercury capture.
- J. Toxecon I systems cannot be used simultaneously with dry FGD systems.



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- K. Installation of an SCR is assumed to have no effect on speciation of sub-bituminous fuel or capture beyond the existing baseline.
- L. An 8% loss of present fly ash sales will be assumed for implementation of Toxecon II. A 100% loss of fly ash sales will be assumed for duct sorbent or activated carbon injection upstream of an existing ESP.
- M. Toxecon II will be considered only for those units with adequate ESP collection area (SCA) for the application (i.e. Edgewater 4).
- N. While full-scale operating data is limited, SO<sub>3</sub> ash conditioning appears to have a significant effect on elemental mercury collection by fly ash and activated carbon. This study assume a 50% reduction in Hg collection efficiency if activated carbon is injected upstream of an ESP utilizing SO<sub>3</sub> ash conditioning.
- O. The following technologies and removal efficiencies are based on typical PRB fuels with the above speciation and shall be the candidates for all units unless site specifics precludes their implementation:

**Table 4-6**

Mercury Reduction Technologies  
Stand-Alone Removal Efficiencies

Hg Control Technology	Removal Efficiency	Notes
Co-benefit with LSFO (no absorber additives)	80% of oxidized portion	Assumes re-emission of 20% of the oxidized form.
Co-benefit with LSFO (with absorber additives)	90% of oxidized portion	
Co-benefit with LSD or CFB (No Sorbent Injection)	24% of total	
Co-benefit with SCR+LSFO	As above LSFO co-benefit	Oxidized portion increases from 30% to 34.5%
Activated Carbon Injection upstream of existing ESP.	70% of total	
Activated Carbon Injection between existing ESP and Dry FGD system (LSD or CFB).	90% of total	
Toxecon I	85% of total	
Toxecon II	60% of total	
Fuel Additive – existing hot side ESP, only	10% of total	
Fuel Additive – existing cold side ESP, only	30% of total	
Fuel Additive + Hot ESP + LSFO	50% of total	No SCR
Fuel Additive + Cold ESP + LSFO	70% of total	No SCR
Fuel Additive + ACI	80% of total	* No SO <sub>3</sub> ash conditioning



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## 5.0 TECHNICAL INPUTS

### 5.1 Unit Capacities and Baseline Emissions

- A. Alliant Energy Capacity factors were back-calculated from Alliant's Emissions Model yearly unit outputs, baseline emissions and detailed plant data, as submitted responses to Washington Group plant data sheets. Refer to Appendix A, Baseline Emissions Data and Capacity Factors.
- B. The first baseline target (2015/18) solution for selection of SO<sub>2</sub> and NO<sub>x</sub> technologies was set as close to +0/-10% allowance credit range as possible so that the model would converge with the solution allowing sales, but no purchase of allowances. This range was broadened to allow purchase or greater sales of allowances if the initial run did not converge.

### 5.2 Fuels

- A. The range of PRB fuels and their compositions are given in the referenced Fuel Assessment Study. The design fuels are plant-specific, based on the highest average sulfur source at each plant. Refer to Appendix B.
- B. The baseline emissions will include fuel blending with petroleum coke or higher-sulfur bituminous fuels where currently applicable (e.g. Sutherland).
- C. The minimum as-received chloride content of each coal is assumed to be 0.01 wt%.

### 5.3 IECCOST Input Data

- A. Refer to Appendix A, Summary of Input Data for Compliance Model, for inputs that are required by the Compliance Model and which are also used by IECCOST.
- B. The IECCOST output sheets, Appendix E, shall be the basis for the optimization model technical inputs.

### 5.4 Unit-Specific Factors and Constraints

#### A. (WPL) Columbia 1

1. NO<sub>x</sub>: RRI will not be considered.
2. NO<sub>x</sub>: SmartBurn is already installed.
3. Hg: Hot side ESP

#### B. (WPL) Columbia 2

1. NO<sub>x</sub>: RRI will not be considered.
2. NO<sub>x</sub>: SmartBurn is already installed.
3. Hg: AC technologies installed upstream of the existing ESP will be 50% less efficient due to SO<sub>3</sub> ash conditioning.

#### C. (WPL) Edgewater 3

1. Edgewater 3 shall be considered an uncontrolled unit for all pollutants.



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**D. (WPL) Edgewater 4, 5**

1. NO<sub>x</sub> : SmartBurn will not be considered for either unit 4 or 5.
2. Hg: AC technologies installed upstream of the existing ESP at Edgewater 4 will be 50% less efficient due to SO<sub>3</sub> ash conditioning.
3. Hg: Toxecon II will not be considered for Edgewater 4 because of limited ESP SCA.

**E. (WPL) Nelson Dewey 1, 2**

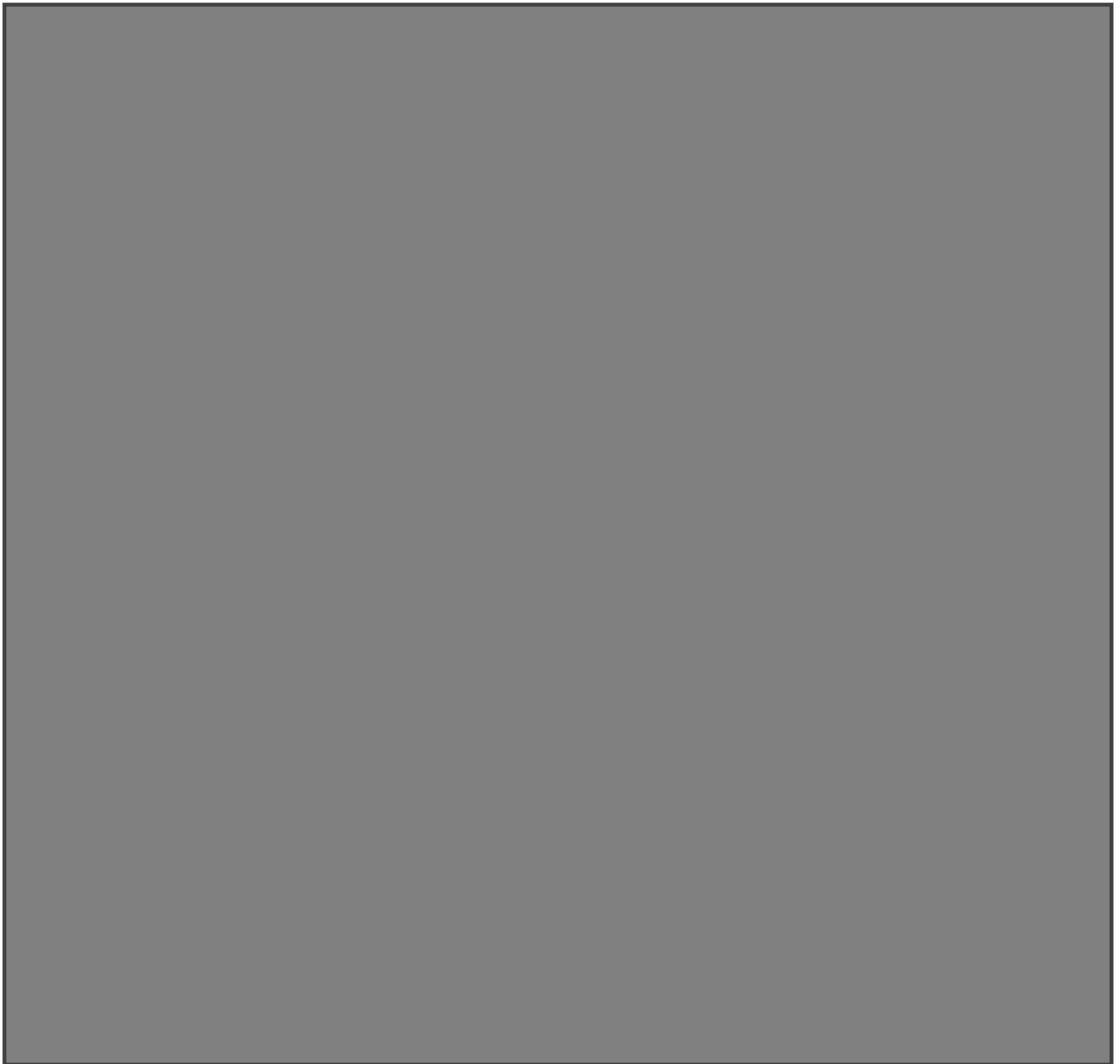
1. NO<sub>x</sub>: SmartBurn will not be considered for either unit 1 or 2.
2. SO<sub>2</sub>: A single LSFO FGD absorber module, common to both units, will be considered. There will be three potential LSFO solutions for Nelson Dewey plant:
  - Unit 1, only
  - Unit 2, only
  - Combined Units 1 and 2



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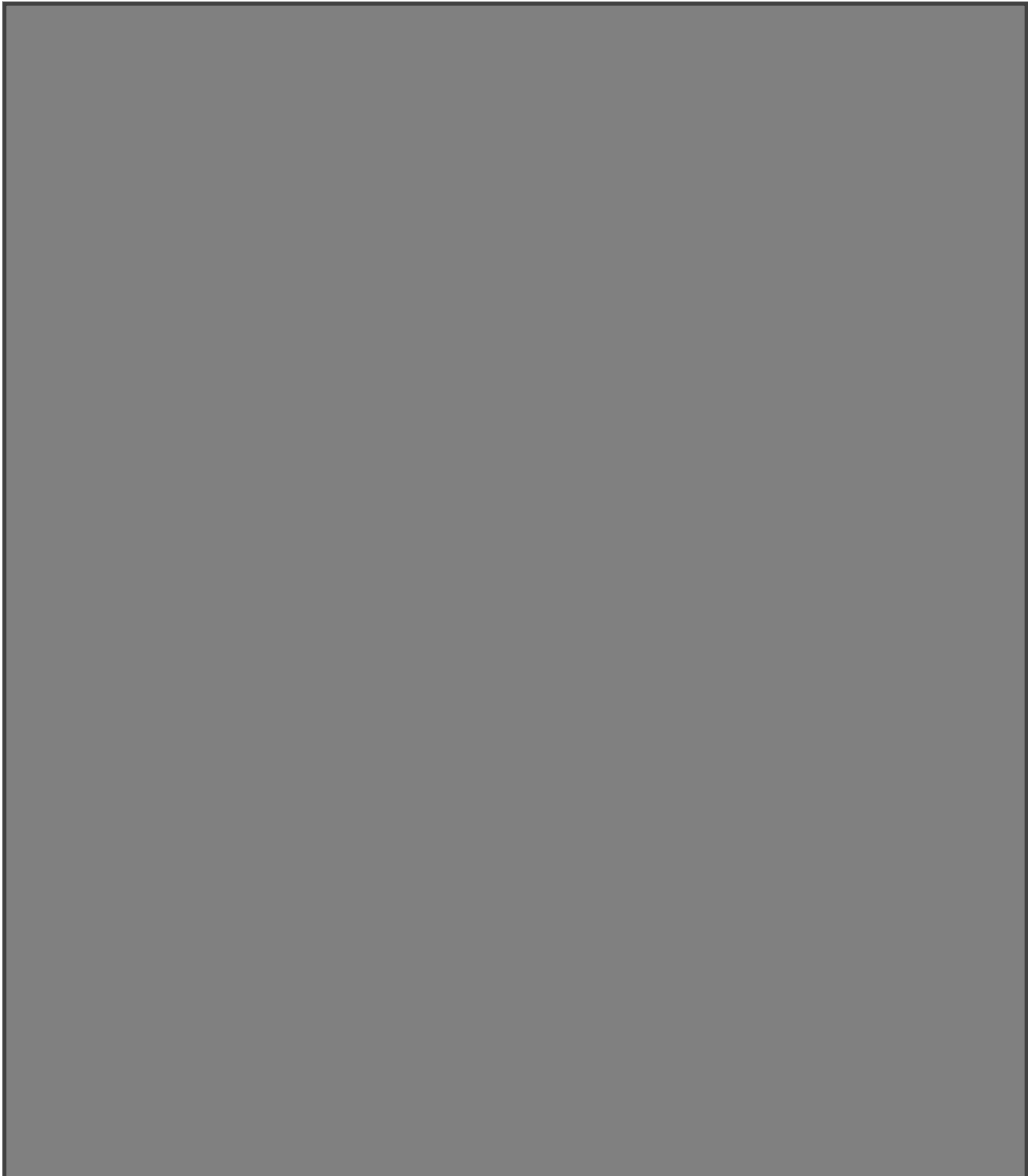






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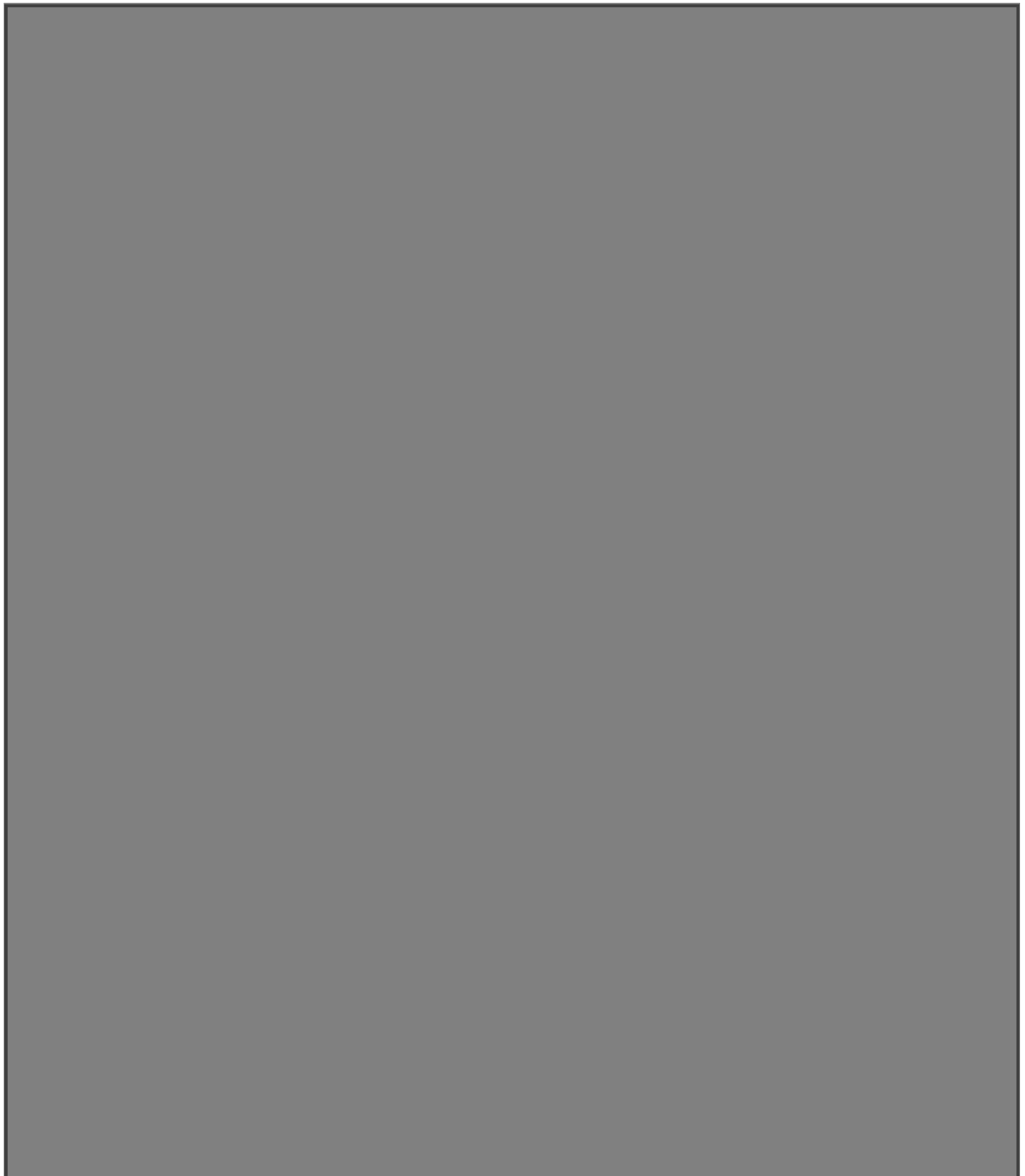




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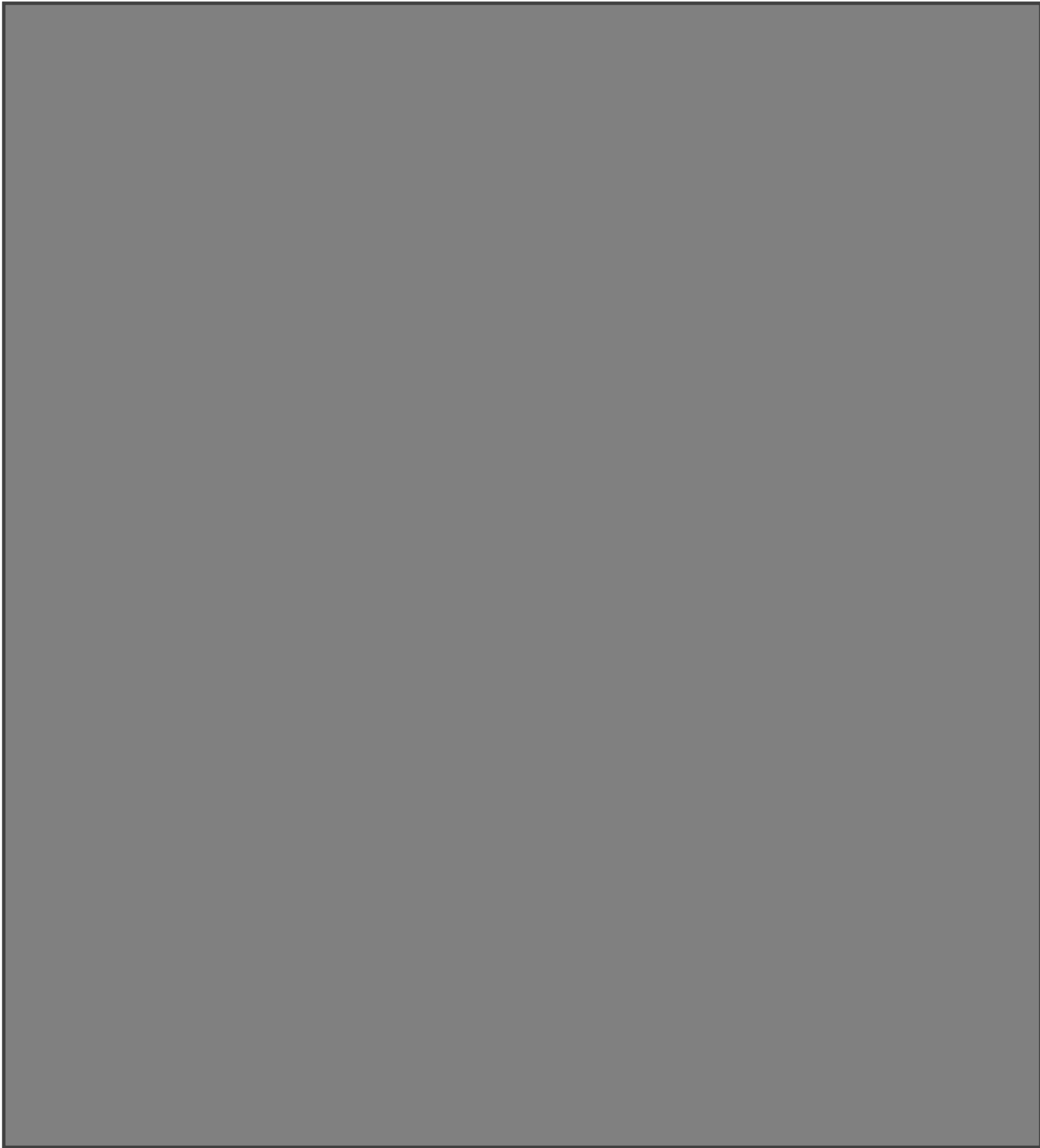
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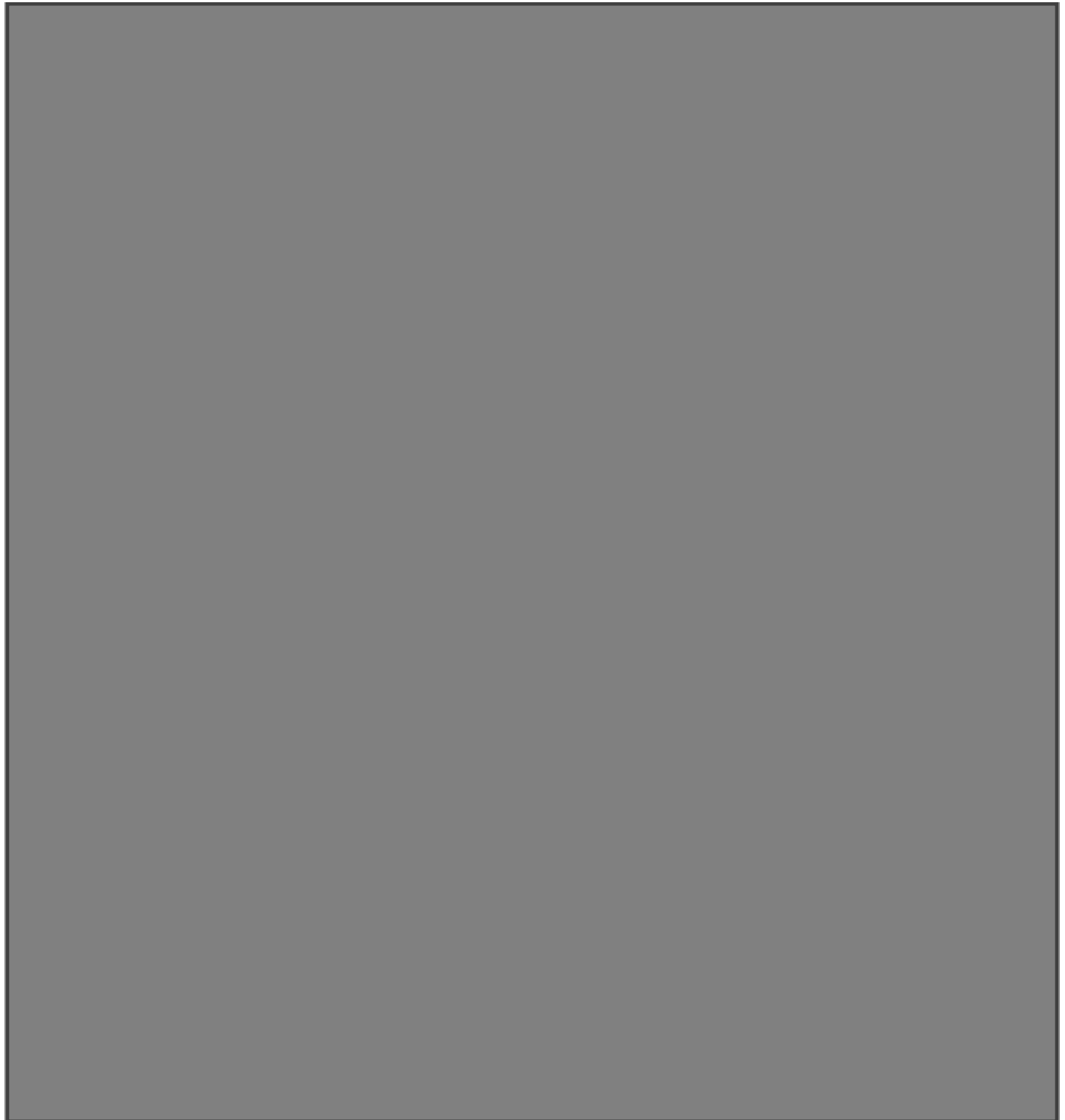
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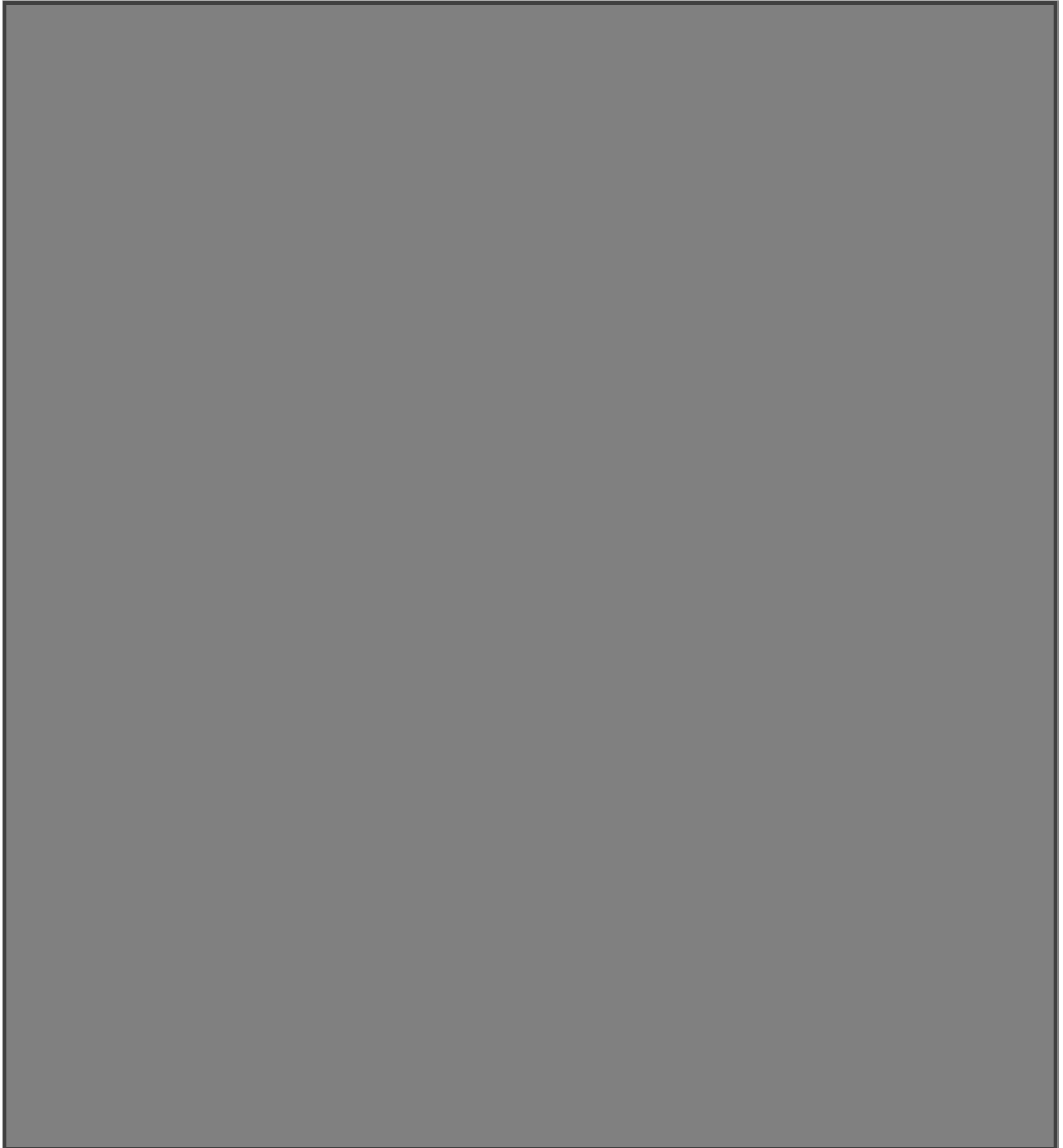
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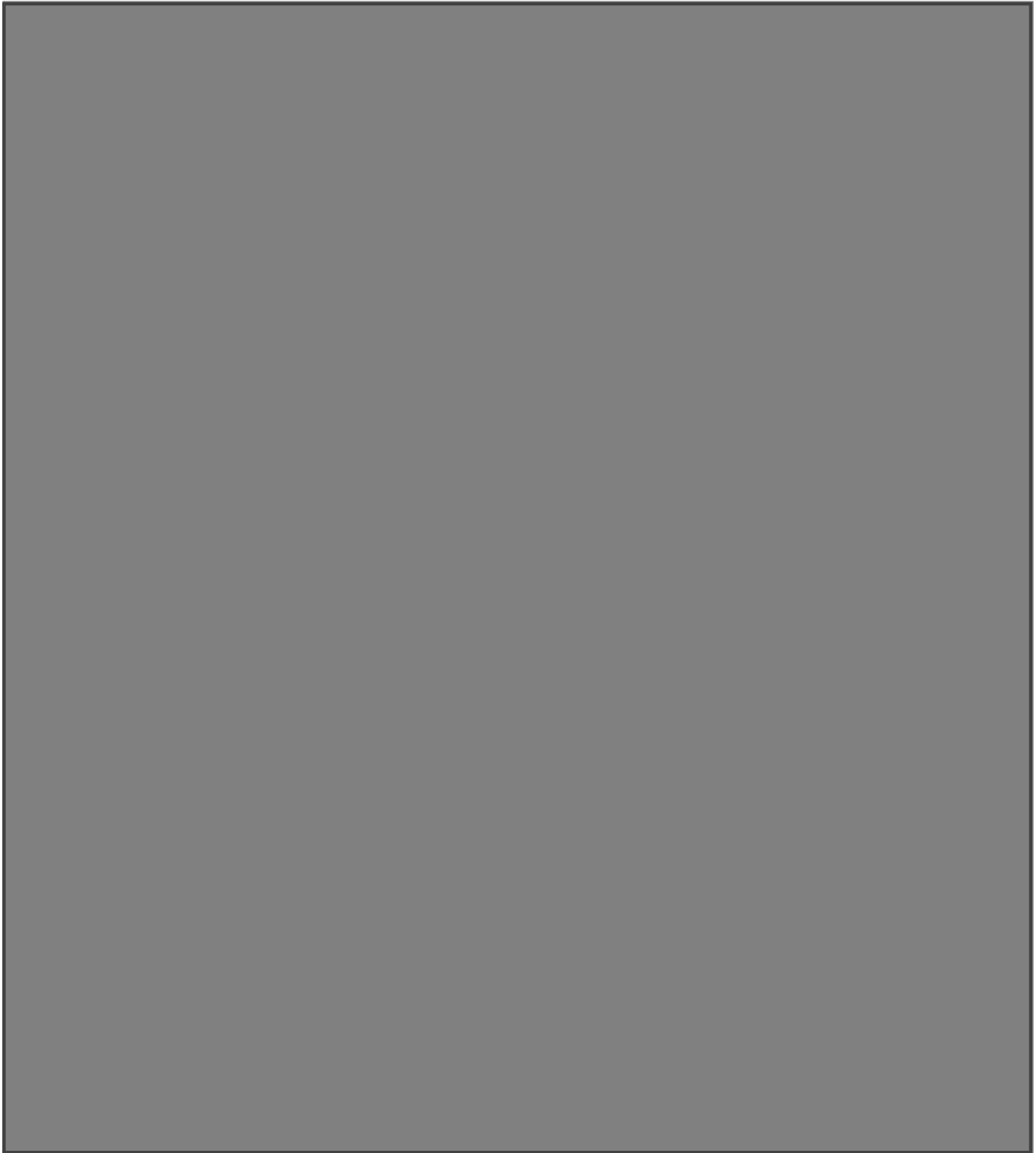




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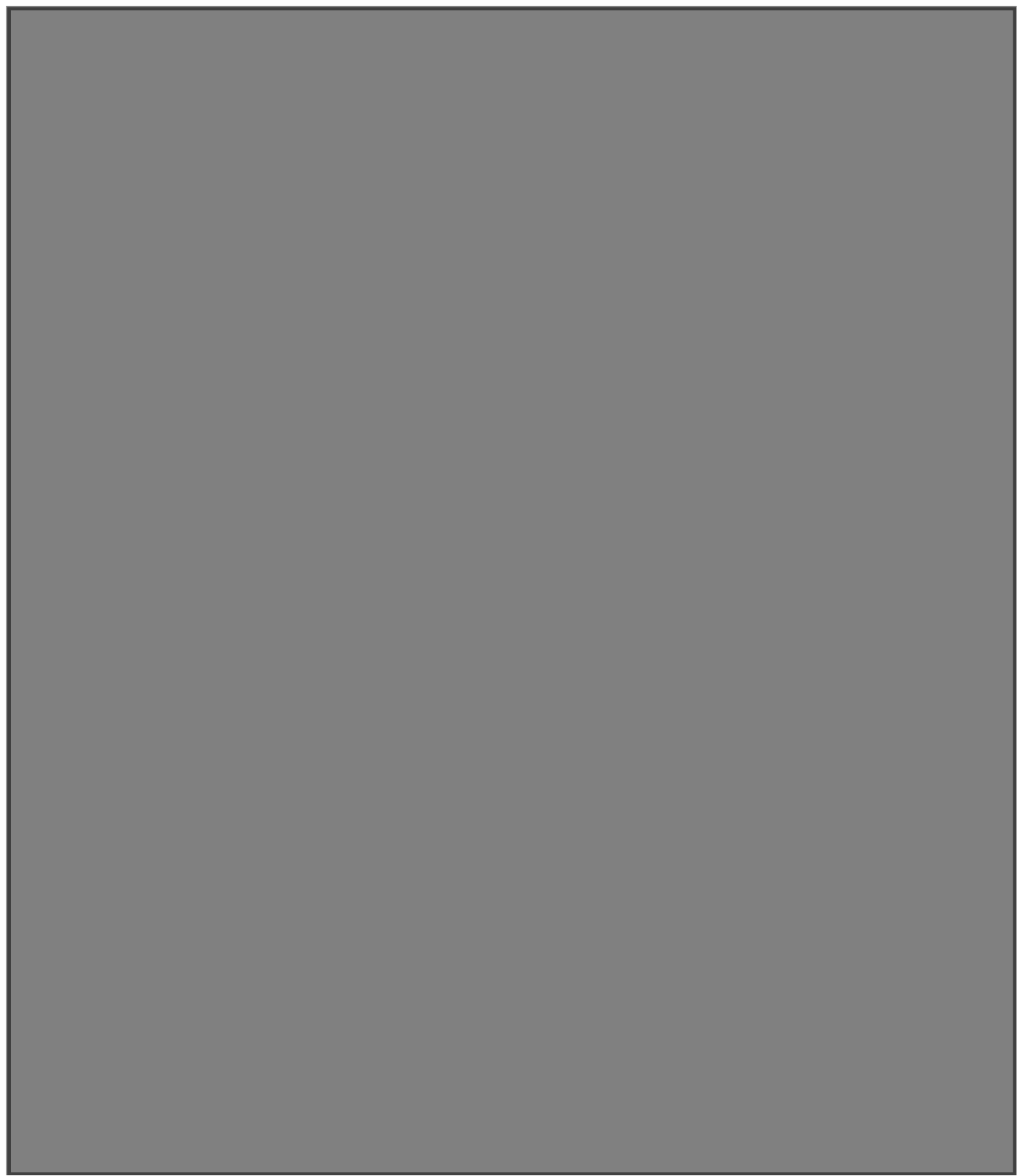
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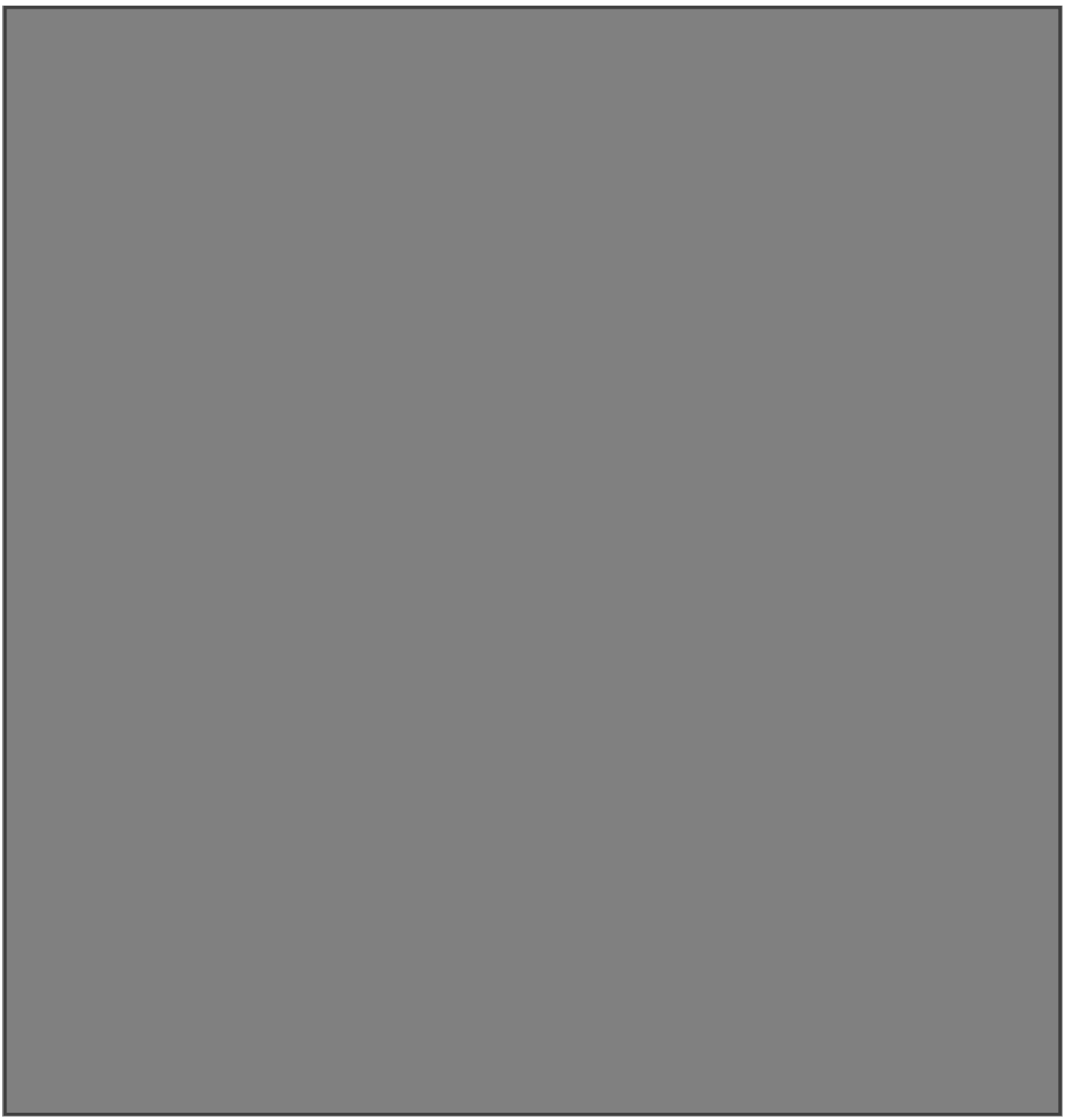




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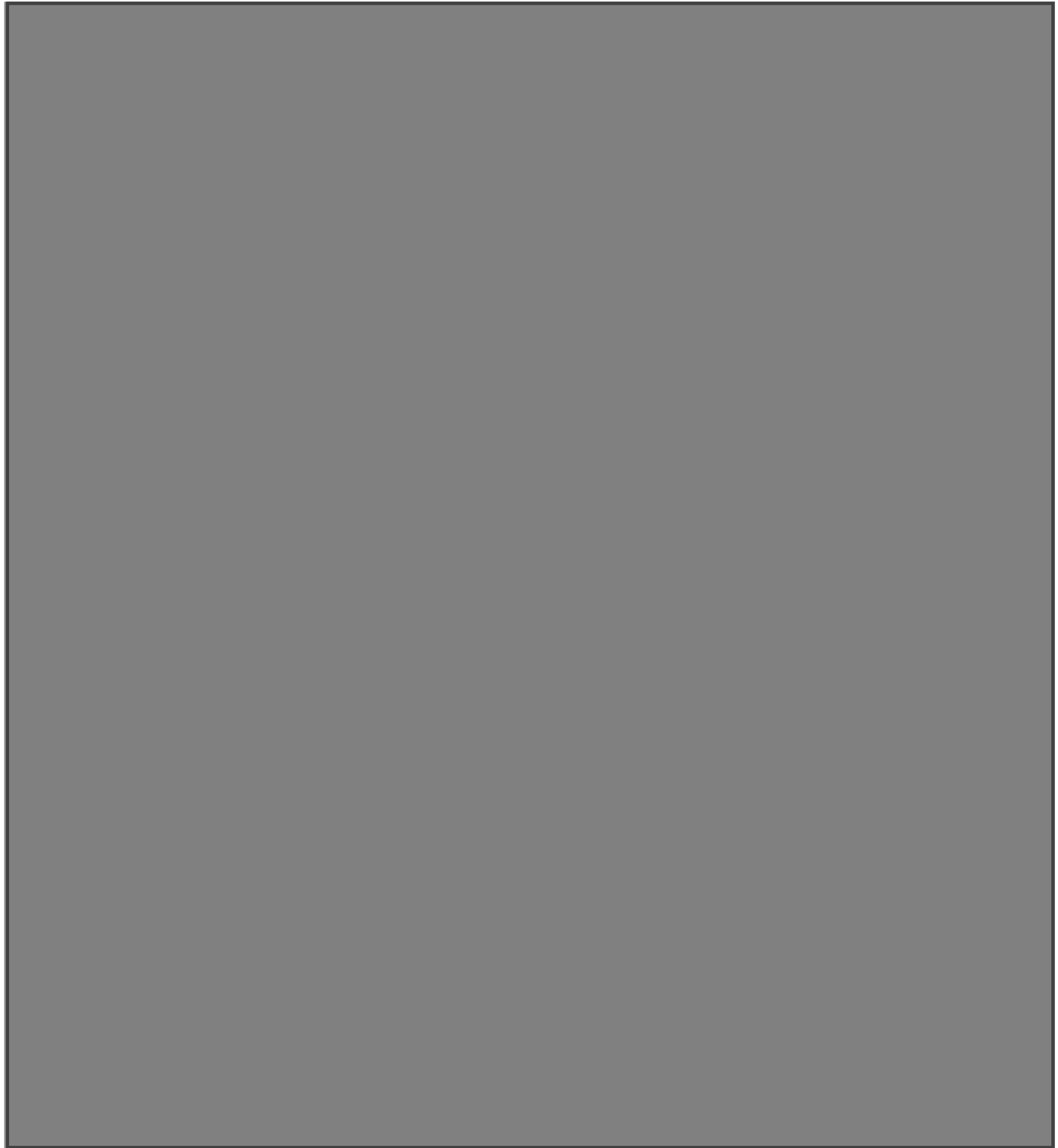






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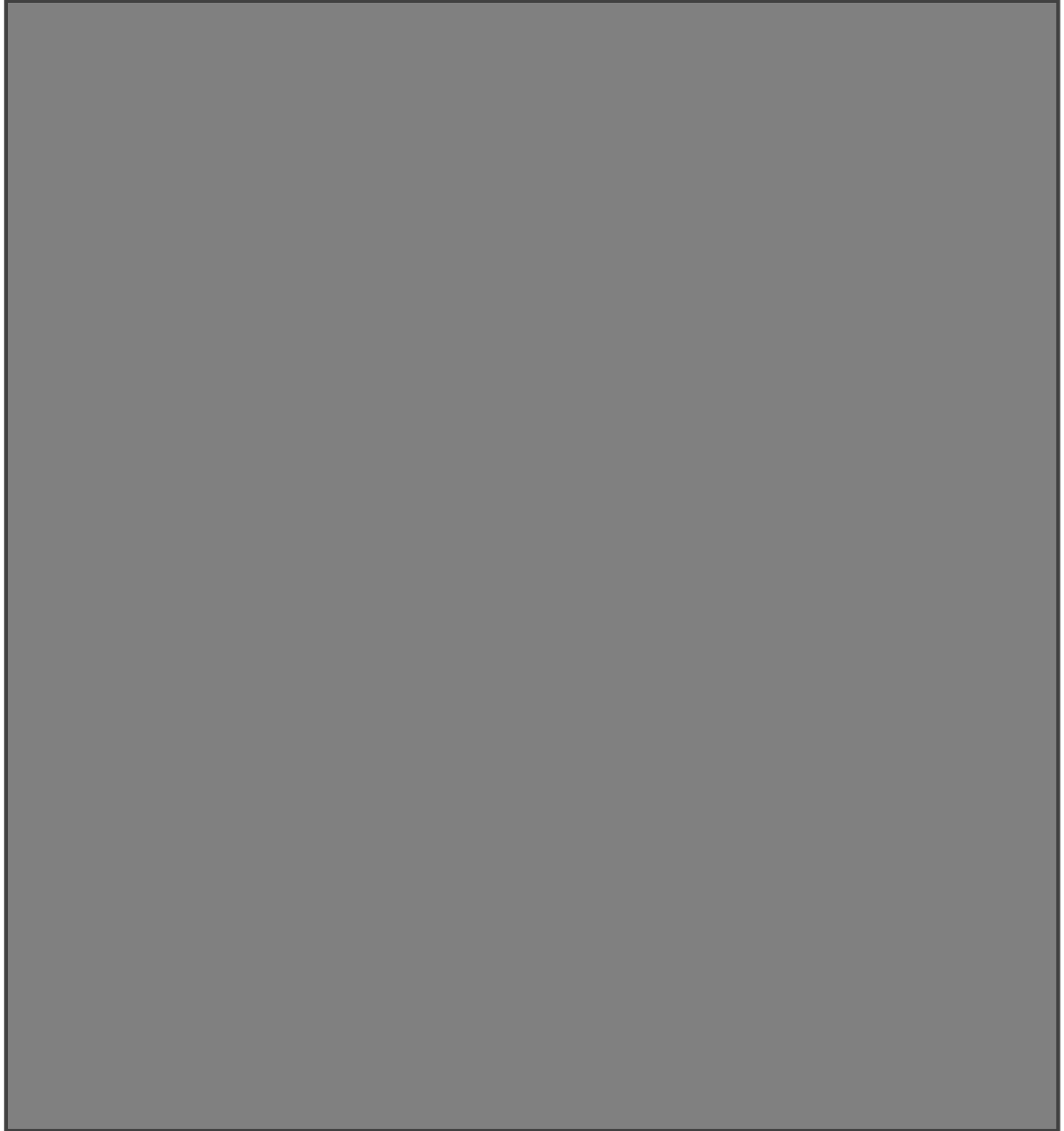




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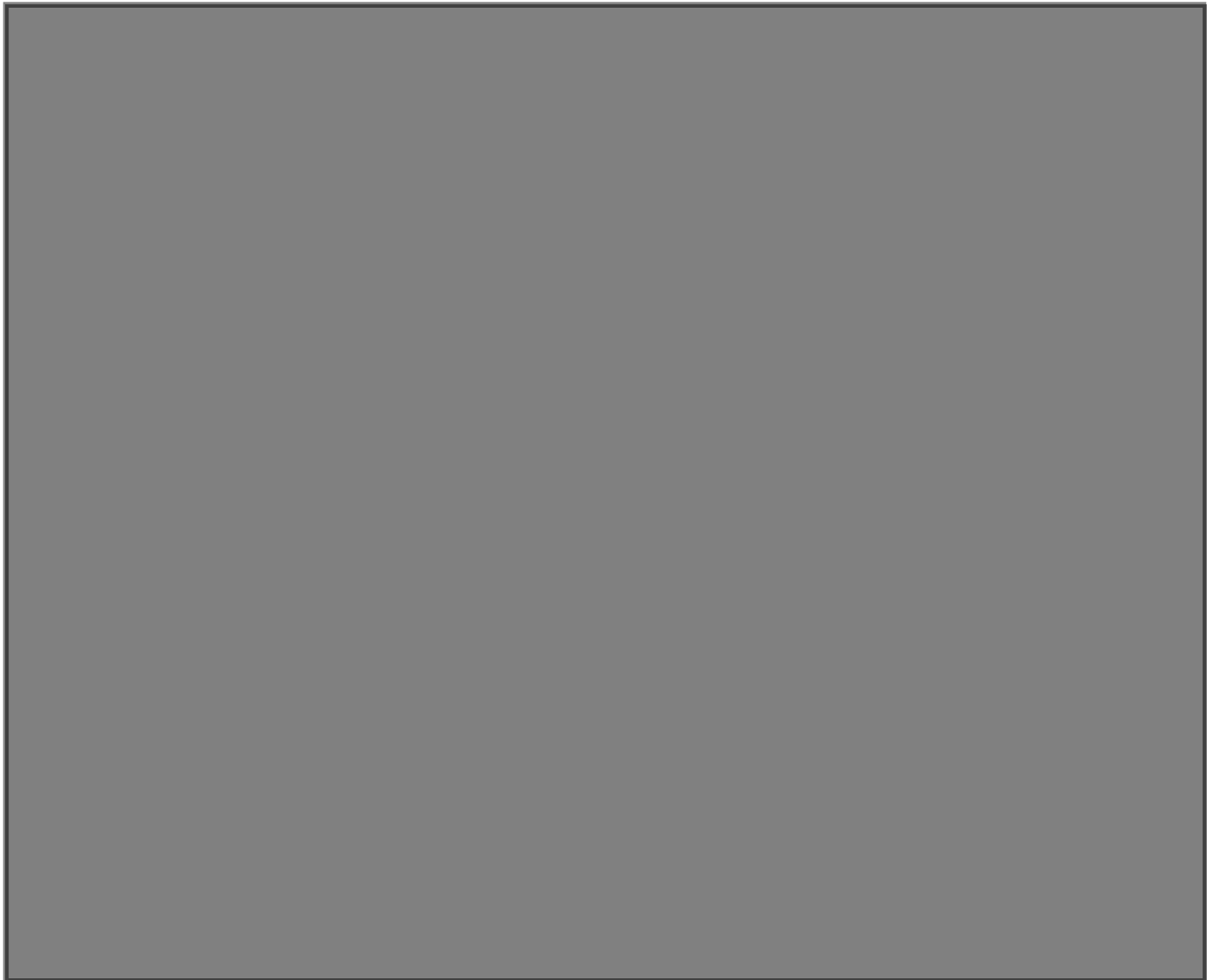




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The CACP model produced the least-cost technology solutions to the early and late compliance years that considered technology combinations and co-benefits specific for each unit in the fleet, capital expenditures, and fixed and variable O&M costs. Various constraints were provided in the Model in order to produce the solutions. They include, but not limited to, the following:

- Optimized least cost solutions with Alliant Energy's ownership portion only;
- Emissions Allowance Market Neutral position;
- Emission inventory based on current fuels; and
- Only Columbia Units 1 & 2, Edgewater Units 4 & 5, and Nelson Dewey Units 1 & 2 are considered.

The CACP model validated the technologies provided in AE's model and presented the cost savings and reductions in allowance purchases that could be achieved by early implementation. It should be noted that the Model assumed an overnight implementation of all technologies. However, in real life, there is a practical limits to how many technologies can be implemented at the same time considering the capital costs, resource availability, outage requirements, ability for the market to support such a large program, and other political and regulatory issues. It is expected that the final "solutions" would be bound by the technologies selected between the early and late compliance solutions. This final solutions will be higher in cost than the least cost, early compliance solutions; but should be less than the late compliance solutions. Alliant Energy can use these results, along with cash flow, allowance markets, regulatory, political, and other external factors, to develop their implementation schedule for the fleet. As newer technologies (particularly mercury reduction and/or multi-pollutant reduction) become available and allowance markets (particularly NOx and Mercury) are developed over the life of the implementation plan, the model can be updated for the outlying years, as required.

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## APPENDIX-A

### BASELINE TOTAL UNIT EMISSIONS and CAPACITY FACTORS



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**APPENDIX – B**

**SO2 CONTROL TECHNOLOGY DESCRIPTIONS**

- 1.0 Limestone Forced Oxidation (LSFO) System**
- 2.0 Lime Spray Drying (LSD) System**
- 3.0 Circulating Fluidized Bed (CFB) Absorption System**

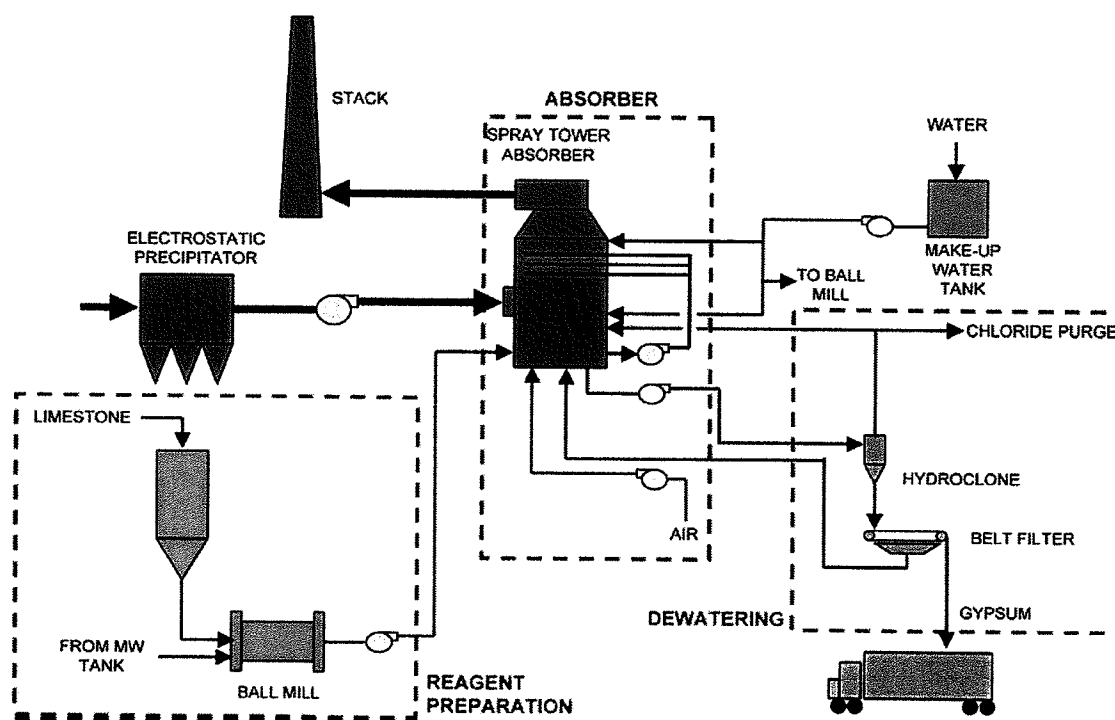


## APPENDIX – B SO<sub>2</sub> CONTROL TECHNOLOGY DESCRIPTIONS

### 1.0 Limestone Forced Oxidation (LSFO) System

#### 1.1 LSFO Process Description

In the LSFO process, hot flue gas exiting the new booster existing ID fans enters an absorber where it is contacted with a dilute calcium carbonate and calcium sulfate slurry (typically 15%-20% by weight suspended solids). The dissolved SO<sub>2</sub> reacts with the calcium carbonate in the limestone particles and the slurry drains into the absorber reaction tank (integral with the absorber). Limestone with forced oxidation FGD is a modification of the traditional wet limestone FGD process and involves continuous sparging of air into the reaction tank (sparging air is provided by dedicated air compressors). This process alleviates problems such as gypsum scaling and dewatering difficulties that plagued the early natural oxidation, wet limestone processes. LSFO offers the advantage of controlled oxidation of reaction products and potentially scale-free operation of the wet scrubber. LSFO produces a salable byproduct in the form of commercial-grade gypsum that can be used for wallboard manufacturing or other industrial applications.



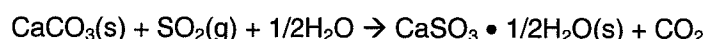




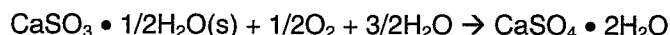
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### SO<sub>2</sub> CONTROL TECHNOLOGY DESCRIPTIONS

The chemistry for the LSFO process begins with limestone (CaCO<sub>3</sub>) reagent, being fed to the spray tower absorber, in an aqueous slurry at a molar feed rate of 1.02-1.03 moles of CaCO<sub>3</sub>/mole of SO<sub>2</sub> removed, when producing wallboard quality gypsum. The major product of SO<sub>2</sub> reaction with limestone is the formation of hydrated calcium sulfite (CaSO<sub>3</sub> • 1/2H<sub>2</sub>O(s)) according to the following reaction:



The sulfite is oxidized by the injection of air into the bottom of the absorber reaction tank, and then hydrated to form calcium sulfate (CaSO<sub>4</sub> • 2H<sub>2</sub>O) through the following reaction:



The absorber may be an open spray tower, a spray tower with a gas/liquid contact tray, a fountain type spray, or a jet bubbler reactor. The contact tray promotes additional removal efficiency but results in additional flue gas pressure drop.

The LSFO process requires makeup water to replace the losses that occur through evaporation, in liquor entrained in the byproduct solids, and due to blowdown streams used to control dissolved solids and fines. This makeup water can be supplied from any source that is not saturated with respect to any of the dissolved solids and contains a relatively low concentration of suspended solids. For example, cooling water tower blowdown is typically suitable for makeup to absorber. However, the mist eliminator wash stream, which serves as a large portion of the scrubber should be higher quality (e.g. plant service water) in order to maintain scale-free operation.

The LSFO process is capable of removing more than 95% of the SO<sub>2</sub> present in the inlet flue gas. For this analysis, 95% SO<sub>2</sub> removal efficiency is used as the LSFO Process design basis, due to sub-bituminous coal application. The 95% removal efficiency will result a 20-25 ppm of SO<sub>2</sub> emission, which is an industry expected practical limit.

The LSFO process requires limestone as its reagent. The following table shows a typical limestone specification.

LIMESTONE PROPERTIES	
CaCO <sub>3</sub> , wt % dry	> 95
CaCO <sub>3</sub> , wt % (available) dry	94
MgCO <sub>3</sub> , wt % dry	0.5 – 3
Total Inerts, wt% dry	3 – 7
Moisture, wt %	7
Particle Size (inch) (no more than 50% < 6 mesh)	≤ ¾" x 0"
Bulk Density, lbm/ft <sup>3</sup>	100
Limestone Dissolution Rate Test	Per EPRI Method or equal
Work Index, kWh/ short ton	13

## 1.2 LSFO Byproduct Handling

The SO<sub>2</sub> reaction with calcium carbonate initially forms calcium sulfite, which is subsequently oxidized to calcium sulfate (gypsum) in the absorber reaction tank. The formation of gypsum crystals in the slurry

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helps to reduce scaling potential by providing suspended crystal surface for crystal growth and reducing the calcium sulfate saturation level in the slurry. A certain level of sulfate super saturation is required for gypsum formation.

The gypsum slurry removed from the absorber reaction tank is partially dewatered to about 50 percent solids using hydroclones. No additives are required to accomplish this separation since gypsum crystals from the LSFO process tend to be relatively large, dense crystals. The hydroclone overflow is returned to the scrubber reaction tank. The hydroclone underflow is directed to a secondary dewatering facility, which uses either rotary drum or belt filters. The cake coming off of the belt filter is typically 90 percent gypsum solids and 10 percent water. If the gypsum is to be sold for industrial use (e.g. wallboard or cement manufacturing), a washing sequence is included in the vacuum filter design, to reduce chloride content and eliminate contamination. Only water low in dissolved and suspended solids should be used for washing the gypsum filter cake. The cake wash water is usually heated to promote drying to less than 10% moisture.

The gypsum from the vacuum filter is transferred by belt conveyor to a storage building, when it is to be sold for wallboard production. The gypsum is offloaded from the storage area by conveyor to trucks, or railcars for shipment to the wallboard plant.

For PRB fuels, vertical basket centrifuges have been shown to be a cost-effective alternative to vacuum filters due to their lower net power requirements, flexibility in handling different feed concentrations and capability to produce dry cake with a range of moisture content up to 94% dry cake. In addition, a line of batch centrifuges may be placed directly above the gypsum storage building, thereby eliminating material handling conveyors.

**1.3 LSFO Purge Wastewater Treatment**

Blowdown of a portion of the process water returned from the gypsum dewatering/washing process is necessary to control the concentrations of dissolved solids in the scrubber liquor as it concentrates due to the continuous recycle of scrubber slurry and evaporation of water into the flue gas. The blowdown stream is used primarily to control chloride levels in the absorber reaction tank and recycle system. A typical equilibrium chloride level is 12,000 to 15,000 ppm. This level is comparable with the use of 2205 duplex stainless steel. The blowdown stream may also be used to purge fines, which tend to blind filter cloths, leading to difficulties in dewatering.

The quality of wastewater purge stream from the FGD process depends upon the sources of makeup water, the coal composition, and the byproduct specifications. Contaminants that may require removal could include trace heavy metals and chlorides. Multi-stage treatment systems are typically used, consisting of precipitation, flocculation, and dewatering equipment to address Hg, Fe, Cd, and other contaminants. Sodium hydroxide or lime is added to increase the pH to approximately 9 where many metals will tend to precipitate out of the solution. Sodium sulfide is then added to precipitate additional metals to levels of less than 0.1 ppb. Ferric chloride is then added to remove excess sulfides and to produce large flocs of solids that are easily dewatered. Generally, chlorides are not removed and are carried out with the WWT system discharge. The solids generated by these treatment systems have to be disposed in an environmentally acceptable manner. The liquid stream can be used for coal pile wetting, ash sluicing, and/or combined with the plant cooling water discharge.



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**1.4**    **LSFO Limestone Reagent**

Limestone from the bulk storage area is transferred to local storage area by trucks or trains. The reclaim system includes a vibrating feeder and conveyor system to transfer limestone to day bins. Limestone day bins and feeders supply limestone to either a horizontal or vertical type ball mills. The ball mills grind the limestone to 95 percent less than 325 mesh and use a wet recycle classification loop to ensure proper size distribution to the process. This particle size produces a large surface area for gas contact without excessive power consumption by the ball mill. The 30-35 percent solids slurry from the ball mill system is stored in limestone slurry tanks prior to transfer to the absorbers.

**APPENDIX – B**  
**SO2 CONTROL TECHNOLOGY DESCRIPTIONS****2.0 Lime Spray Drying (LSD) System****2.1 LSD Process Description**

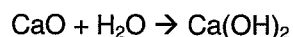
The lime spray drying process is a semi-dry FGD system that produces a dry mixture of fly ash and reaction products. In the Lime Spray Dryer process, the hot flue gas exiting the existing induced draft fans enters a spray dryer vessel. Within the vessel, atomized slurry of lime and recycled solids contact the flue gas stream. The sulfur oxides in the flue gas react with the lime and fly ash alkali to form calcium salts. The water entering with the slurry vaporizes, lowering the temperature and raising the moisture content of the scrubbed gas. In some spray dryer designs, the scrubbed gas leaves from the side of the vessel, and a portion of the dried reaction products and fly ash drop out in the conical bottom.

The spray dryer outlet temperature is typically controlled within 1-2°F of the operating set point (normally 30-35°F above the gas saturation temperature). If the coal sulfur content varies over a wide range in a short period of time, there might be a tendency to operate outside of the normal outlet temperature range. A closer approach to the saturation temperature allows the LSD system to achieve higher removal efficiency for a short period, but at the same time risks the buildup of wet solids on internal surfaces. This could be a major concern if the coal sulfur contents are expected to change significantly.

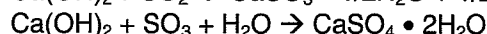
A particulate control device is required downstream of the spray dryer. A fabric filter downstream of the LSD vessel removes the dry solid reaction products, unreacted reagent, and fly ash before the scrubbed gas is released to the atmosphere. The fabric filter bags collect a layer of solids on their surfaces between cleanings, and the movement of the flue gas through this layer enhances the gas-solid contact. A portion of the collected reaction product and fly ash solids is recycled to the slurry feed system. The remaining solids are transported to a landfill for disposal.

The following chemical reactions define how the sulfur dioxide is removed from the flue gas in the lime spray drying process:

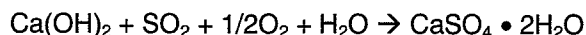
Raw lime is slaked with an excess of water to form a calcium hydroxide slurry:



The sulfur oxides in the flue gas are absorbed into the slurry and react to form the salt products:



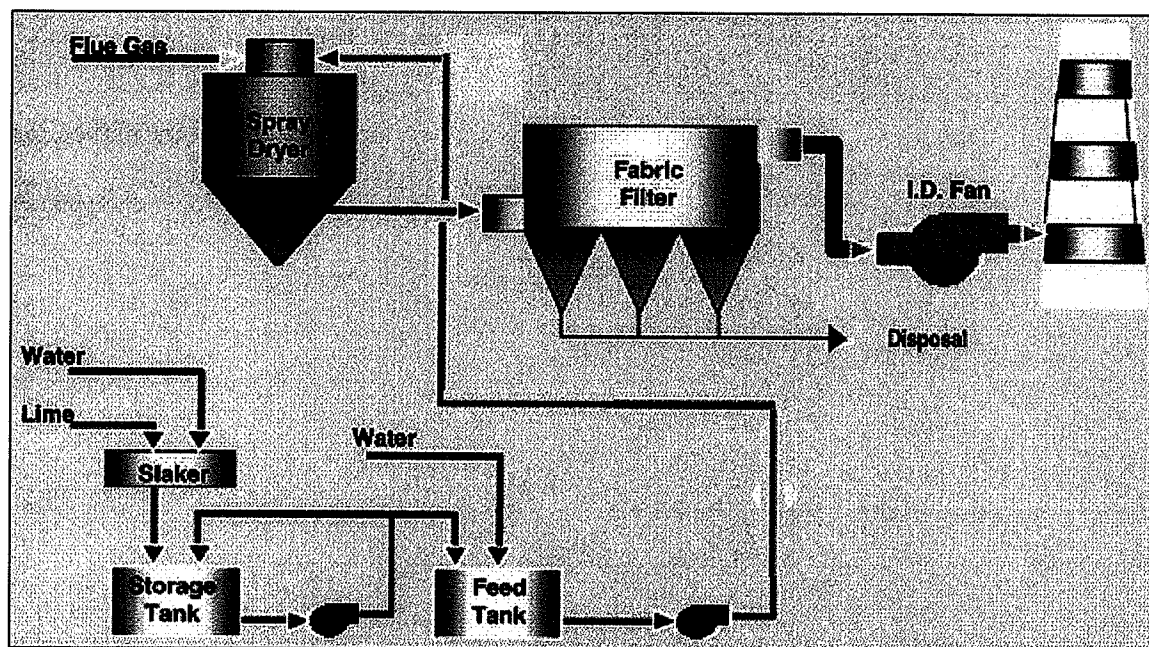
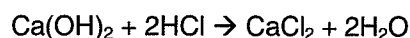
A fraction of the sulfite product may also be oxidized to the sulfate form by reaction with oxygen in the flue gas:



Any HCl in the flue gas, present because of the chloride content of the fired coal, also absorbed into the slurry and reacts with the slaked lime by:



## APPENDIX – B SO<sub>2</sub> CONTROL TECHNOLOGY DESCRIPTIONS



The majority of the water evaporates in the spray dryer, leaving dry particles composed of the reaction products, unreacted absorbent, and fly ash. In the particulate control device, the remaining SO<sub>2</sub> continues to react with the residual lime in the collected solids, although, at a much slower rate. As much as 25% of the total SO<sub>2</sub> removal can occur in the baghouse. In addition, the LSD process is highly effective controlling sulfur trioxide, which condenses with water vapor to form sulfuric acid. Over 90% of the sulfur trioxide that is formed during combustion is absorbed in the LSD vessel and FF. This eliminates the potential for plume opacity due to acid mist or sulfuric acid corrosion in the downstream ductwork and particulate collection system. However, if the outlet gas temperature drops too low, then water condensation can occur on downstream surfaces. The water droplets can absorb additional SO<sub>2</sub> producing sulfurous acid, increasing the potential for corrosion, and can form a mud that can plug the filter bags.

The Lime Based Semi-Dry LSD system can meet the specified 0.07 lb/MMBtu SO<sub>x</sub> emission and 92% removal efficiency for the design coal. To achieve higher than 92% SO<sub>2</sub> removal, plant operators must closely watch the LSD system operation and adjust the process control parameters frequently. Any variation of boiler operations can cause the SO<sub>2</sub> emission to exceed the limits. Based on industrial experiences a 92-93% SO<sub>2</sub> removal can be consistently achieved. The LSD system for each Columbia Unit will be comprised of two spray dryers, followed with one fabric filter module. This fabric filter will have multiple compartments so that if a compartment is down for maintenance or cleaning, the unit can still operate at full load.

### 2.2 LSD SO<sub>2</sub> Removal Capabilities and Other Performance Parameters

The LSD process is capable of removing up to 92% of the SO<sub>2</sub> present in the inlet flue gas.



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The LSD process requires pebble lime as its reagent. The following table shows a typical lime specification.

PEBBLE LIME PROPERTY	
CaO, wt % (Total)	> 95
CaO, wt % (available for reaction)	90 or greater
MgO, wt %	2% max
Inerts, wt %	5
Moisture	Negligible
Particle Size (inch)	1/4" to 3/8"
Bulk Density, lbm/ft <sup>3</sup>	55 – 60
Reactivity	Slaking rate test - Achieve 40 °C temp rise in 3 min. or less

**2.3 LSD Reagent**

The reagent used in lime spray drying is lime in pebble form. Fresh slaking water is introduced which hydrates the pebble lime. A ball mill slaker pulverizes the inert material and maintains the inerts with the reagent slurry. If a detention or paste slaker is used, the grits are removed at the slaker for separate disposal. The slaked lime, Ca(OH)<sub>2</sub>, flows to an agitated lime slurry feed tank, and this slurry is then pumped to the lime spray dryer rotary atomizer.

**2.4 LSD Waste/Byproduct Handling**

The spray dryer system produces a dry solid product consisting of calcium sulfite/sulfate, unused hydrated lime, and fly ash. These dry solid products can be handled by conventional dry fly ash handling systems. A portion of the collected reaction product and fly ash solids is recycled to the slurry feed system and the remaining solids are sent via the dry solids conveying systems to a storage silo. From the silo they are trucked to a landfill for disposal.



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**3.0 Circulating Fluidized Bed (CFB) Absorption System**

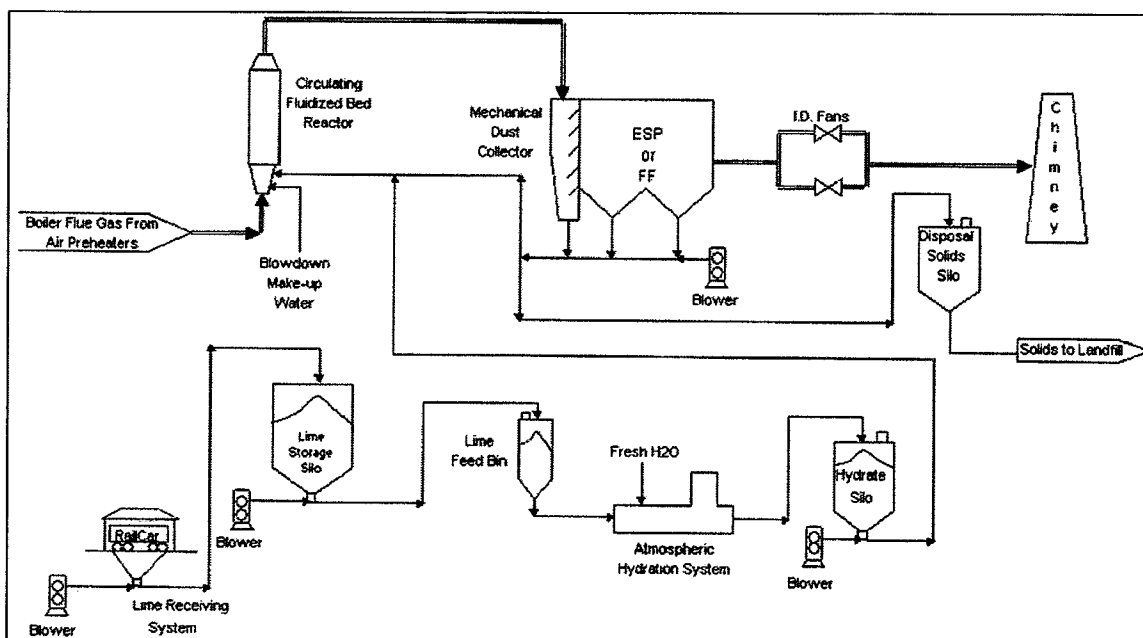
**3.1 CFB Process Description**

The Circulating Fluid Bed Scrubber (CFB) process is a dry scrubbing technology. The process is totally dry, meaning it not only produces a dry, free flowing disposal product but also introduces the lime reagent as a dry, free flowing powder.

In a Circulating Fluid Bed (CFB) process, the flue gas enters the bottom of the fluidized bed reactor(s). As the flue gas enters the venturi-shaped entrance to each reactor, it is mixed with hydrated lime reagent and recycled fly ash and reaction product solids. Water is injected into the reactor to humidify the flue gas and assist in SO<sub>2</sub> removal.

The CFB reactor has a tall cylindrical configuration to allow adequate time for the mixing of the SO<sub>2</sub> laden gas with the reagent to complete the reaction. Calcium salts are formed when the hydrated lime and fly ash react with the sulfur oxides in the flue gas.

The spent solids and fly ash are carried out of the top of the reactor and captured downstream by a fabric filter or an ESP, one for each CFB Reactor. A portion of these combined solids is recycled to the fluid bed absorber via air slides. The remaining material is transported to a disposal solids silo. The fly ash and reaction products are drawn from the silo and conditioned in a pug mill(s) for disposal to landfill.



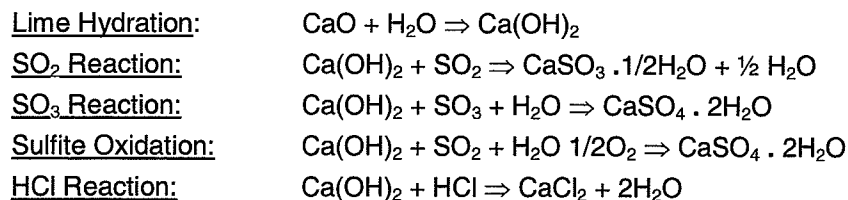


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The Circulating Fluid Bed process chemical reactions are similar to that of the Spray Dryer Absorber, as shown below:



Pebble lime is transported pneumatically from the lime storage silos to the lime day bin which feeds the dry lime hydration plant. From the day bin, pebble lime is charged into a lime hydrating fluid bed reactor. The pebble lime is hydrated by the injection of fresh water in the hydrating reactor in an amount proportional to the feed rate of the pebble lime. Hydrating water consumption is approximately 150% of the stoichiometric requirement. The highly reactive hydrated lime product is pneumatically transported by one of two 100% capacity hydrate transfer blowers to the hydrated lime surge bins, one for each CFB tower. The hydrated lime reagent is drawn from each hydrated lime surge bin by a variable speed rotary feeders which transfer the hydrated lime to an airstide which conveys and feeds the hydrated lime into the associated scrubber tower.

The hydrated lime feed rate through the variable speed rotary feeder and airstide into the CFB is adjusted based on a feed forward signal from the SO<sub>2</sub> inlet and outlet monitors. Injection of water directly into the CFB reactor further enhances SO<sub>2</sub> removal efficiency making more than 95% removal efficiency theoretically feasible with this technology. However, since high removal efficiencies of 95% have not been commercially demonstrated in FGD systems serving large power plants, the evaluation of CFB technology in this analysis is based on 94% SO<sub>2</sub> removal. Furthermore, the stoichiometric ratio, and the associated lime consumption rate for SO<sub>2</sub> removal levels greater than 95% have not yet been accurately determined or demonstrated.

The evaporation of water within the CFB reactor results in decreased flue gas temperature and increased humidity. Desulfurized flue gas exits the CFB reactors and is drawn through a fabric filter, one per CFB reactor. Hydrated lime and SO<sub>2</sub> reaction products are separated from the flue gas and collected with the fly ash in the new fabric filter hoppers. The fly ash and reaction solids are discharged from the hoppers and split into two streams. The first stream is recycled via an airstide and fed back into the lower section of the associated CFB reactor. The second stream is discharged through an airlock hopper and transported by a pneumatic pressure conveying system to a fly ash / reaction products storage silo. The fly ash and reaction products are gravity discharged from the silo into a pug mill. The pug mill conditions and discharges the ash and reaction products into ash dump trucks for transportation to the landfill.

The flue gas exiting the fabric filter is ducted to new booster I.D. Fans, and then to the chimney.

### **3.2 CFB System Materials and other Mechanical Considerations**

The CFB vessel and ductwork are typically constructed of carbon steel because sulfuric acid is absorbed and neutralized by the alkaline solids present.

The CFB system includes the dry hydration plant upstream of the reactor vessels.



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Evaluation of the CFB system includes new fabric filter immediately downstream of the reactor vessels to capture the reaction products, unreacted absorbent, and fly ash.

Evaluation of the CFB system includes the costs associated with installation and operation of new booster fans located immediately downstream of the FF.

The additional pressure provided by the new fans compensates for pressure losses due to the CFB's, FF and ductwork.



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**APPENDIX –C**

**NOx CONTROL TECHNOLOGY DESCRIPTIONS**

- 1.0 Combustion Modifications**
  - 1.1 SmartBurn Low-NOx Burners (LNB)**
  - 1.2 Air Staging/Overfire Air**
  
- 2.0 Secondary/Post Combustion NOx Controls**
  - 2.1 Selective Catalytic Reduction (SCR)**
  - 2.2 Selective Non-Catalytic Reduction (SNCR)**
  - 2.3 Hybrid SNCR//SCR**



## APPENDIX – C

### NO<sub>x</sub> CONTROL TECHNOLOGY DESCRIPTIONS

#### 1.0 Combustion Modifications

Burner upgrades and other combustion modifications such as air staging, over-fire air, fuel staging, and combustion tuning technologies are often termed **primary control methods**. These processes typically reduce peak flame temperatures lowering thermal NO<sub>x</sub> formation, while at the same time increasing the concentration of hydrocarbon radicals (radicals aid in the reduction of the nitrogen oxides formed during the combustion process). For the purposes of this study, SmartBurn® Low-Nox Burner systems with overfire air was incorporated as representative of combustion modification technologies. Fuel Gas Reburn and control system modifications were not included.

##### 1.1 Low NO<sub>x</sub> Burners (LNB)

LNBs are designed to control fuel and air mixing at each burner in order to create larger and more branched flame patterns. This reduces the peak flame temperature and results in lower thermal NO<sub>x</sub> production. The modified flame structure also reduces the amount of oxygen available in the hottest part of the flame, improving burner efficiency. Primary combustion, NO<sub>x</sub> reduction, and fuel burnout are accomplished in three stages in a LNB:

- The first stage of combustion occurs in a fuel rich zone where oxygen levels are maintained below the requirement for complete combustion. Most of the NO<sub>x</sub> species are formed in this zone.
- The second stage is a reducing zone where unburned hydrocarbon species act to reduce the NO<sub>x</sub> that was formed in the first stage.
- The third provides internal air staging, which completes the combustion of the available hydrocarbons, but also produces additional NO<sub>x</sub> during the burnout process. Completing the combustion process in an air-lean environment can minimize the NO<sub>x</sub> production rate.

Advanced LNB designs incorporate other design modifications into the burner. These can include distribution of fuel and internal recirculation zones within the burner, producing internal air and fuel staging within the flame. Impellers, adjustable spin vanes, separate gas nozzles, and multiple air nozzles have also been used in some burner designs. Venturi nozzles and gas spreaders have also been used to produce a slower mixing, less turbulent flame.

LNB retrofits at large utility boilers have reported NO<sub>x</sub> reductions of greater than 50% in many cases, with retrofit costs reported to be approximately \$10 to 30/kW depending on boiler size and degree of retrofit difficulty. These projects were implemented without significant reductions in boiler performance or major increases in carbon monoxide emissions.

LNB installations have been combined with other NO<sub>x</sub> control technologies to obtain higher levels of NO<sub>x</sub> reduction. Alternate primary control methods are as follows:

##### 1.2 Air Staging/Overfire Air

Air staging divides the combustion zone into two separate areas. It typically involves the introduction of over-fire air into the boiler. Air staging can also be accomplished in low NO<sub>x</sub> burners (internal air staging). For furnace over-fire air, the combustion air is divided into two streams. Seventy (70) to 90% of the combustion air (primary air) is mixed with the fuel and injected into the furnace through the burners. The lower oxygen concentration helps to minimize flame temperatures, which makes the flame fuel-

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rich/oxygen deficient (producing only moderate amounts of NO<sub>x</sub>). The remainder of the combustion air is typically injected above the primary combustion zone using a separate wind box with air ports positioned 5-10 feet above the burners. The flame volume is increased in the secondary combustion zone, which results in reduced flame temperatures. This secondary "reburn" zone is fuel rich, typically having a fuel to air stoichiometry of 0.8 to 0.9. The air port locations are critical to the success of the over-fire air system, and is unit specific depending on flame profiles, etc.

Air staging typically requires installation of air ports through the existing boiler tube wall, ductwork, dampers, wind box, and modifications to the existing control system. This technology has been applied at more than 300 units around the world as a stand-alone technology or in combination with other NO<sub>x</sub> control equipment.

Variations on the over-fire air system have been given other names based on the location of the ports in relation to the burners: close-coupled over-fire air and separated over-fire air. This technology has been applied to both wall- and tangentially fired boilers. NO<sub>x</sub> reduction varies widely depending on furnace characteristics and whether other control technologies are operating. Some tangential units have reached less than 0.15 lbs/MMBtu while keeping the CO levels below 50 ppm.



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**2.0 Secondary/Post Combustion NOx Control Alternatives**

Secondary control systems are located downstream of primary combustion systems. They can be used independently or in combination with primary control systems. These processes typically use ammonia or urea to react with the NOx in the flue gas to reduce it to molecular nitrogen. The secondary control systems included in this section are Selective Catalytic Reduction (SCR), Selective Non-catalytic Reduction (SNCR), a hybrid combination of SCR & SNCR, and water injection or cannons.

There are many other secondary control technologies on the market at varying stages of development. However, these systems are not commercially proven, so they are not included in this evaluation.

**2.1 Selective Catalytic Reduction (SCR)**

**SCR Design Conditions** - SCRs are generally designed for a maximum inlet gas temperature of 750°F. This operating temperature is below the material property limits of carbon steel; however, it may be above the maximum economizer-exit gas temperature of some units. In addition to this design temperature, other key process temperatures include:

- All units will use air taken from the air heater air outlet for ammonia dilution. Design temperature range will be from 350°F to 600°F for all units.
- In typical installations, the minimum acceptable flue gas temperature to maintain catalyst performance and eliminate problems with ammonia injection is approximately 550-600°F. The actual minimum load, gas temperatures for the units needs to be determined. Further analysis of the low load operating conditions is required during the detailed design phase of the project.

**Furnace Impacts** - The addition of the SCR will increase the boiler gas side operating pressure drop. For balanced draft units, the static pressure in the duct at the air heater (gas side) and ID fan inlet will be more negative than under previous operating conditions. Gas-path pressure changes, including upset or excursion events due to addition of the SCR and the increase in I.D. fan head capability, are determined by evaluation of the current operating pressure, the design pressure, and a suitable margin below design pressure. Any new ductwork would be designed to current guidelines of NFPA 8502. More detailed analysis will need to be made during the design phase to determine whether structural reinforcement is necessary.

**SCR Reactor** - Each SCR reactor housing will support the catalyst modules on guide frames. The reactor assembly generally includes a catalyst removal system. A monorail system is used to move the catalyst into the reactor housing. The joints between modules are sealed to prevent flue gas bypassing the catalyst.

**Common Support Equipment for SCR Installations** - The following subsystems would be common for all units operating at a single site:

- Ammonia Delivery and Storage
- Containment Basins (in case of accidental ammonia release)
- Ammonia Transfer (pumps and piping that transport ammonia to the ductwork on inlet side of SCR reactor)



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**Considerations Regarding Ammonia Supply**

Aqueous or Anhydrous – Anhydrous ammonia is designated to be a hazardous material that requires significant permitting and spill reporting paperwork. A tank rupture or major leak could result in a potentially life threatening environment for a large area of the plant site, and possibly extending beyond the boundaries of the plant. Many facilities have opted for the use of aqueous ammonia. In the event of a spill, aqueous ammonia tends to keep ammonia in the solution, resulting in easier cleanup and a much smaller area that would be impacted within the plant. The major drawback of the use of aqueous ammonia is the added cost to ship all of the water along with the ammonia that is needed. This can double the delivered cost per ton of ammonia consumed.

On-Site Production - One alternative to the storage and handling of large volumes of anhydrous ammonia on the utility site is the use of a urea to ammonia conversion system. These systems are designed to supply continuous ammonia stream that can be varied with changes in load and NO<sub>x</sub> concentration. At least four suppliers are currently offering these systems commercially: Environmental Elements, Hamon, Chemithon, and FuelTech. The Environmental Elements system is currently being installed at a plant located at a Southern Company plant in the U.S., and they have other larger facilities scheduled for installation in the next two years. This technology relies on a recycle stream that is stripped with live steam to produce the ammonia feed.

The Hamon U2A system appears to be simpler in design and operation. The urea is shipped to the site as a solid and dissolved in a salt storage tank. The urea sits on a bed of gravel and deionized water is sprayed onto the urea to form a saturated solution that is withdrawn from the bottom of the tank. This stream is heated to 125°C with steam and maintained in a reboiler at a pressure of 80 psig. The urea decomposes forming a gas stream that is 28% ammonia, 17% carbon dioxide and 55% water vapor. A 300-500lbs/hour feed system would require a 12' diameter dissolution tank and a 10' x 15' skid surrounded by a containment dike. The reactor/reboiler will contain a 3% aqueous solution of ammonia during normal operation. This results in approximately 100 pounds of ammonia being stored on the site at any point in time, which the vendor claims is below the EPA catastrophic spill area of 50 yards. Process gas or air can act as the carrier gas to the NO<sub>x</sub> control system. Every pound of ammonia produced will require approximately 4500 Btu of 250-500 psi steam.

Urea to ammonia conversion systems are currently operating at multiple plants across the U.S., including demonstration plants at 50-300 pounds per hour to full-scale commercial installations exceeding 2000 lbs/hour ammonia (one system capable of 10,000 lbs/hour is currently in the design phase for a 2000+ MW plant). The primary motivation for using the urea to ammonia conversion system is the local perception of the hazards associated with ammonia (anhydrous or aqueous) storage and shipment. The few spills that have occurred along with the zone of influence (radius of impact in the event of a tank failure) issues have caused local agencies to insist on limiting the quantities of ammonia that can be stored on the site.

Process developers have tried using vanadium and molybdenum catalysts to improve on the conversion efficiency, but simply operating at a higher temperature gave the same results. Testing to-date indicates that no unusual species are formed in the reactor.

Ammonia Injection System - Each ammonia injection grid must be designed for even ammonia distribution across the face of the SCR catalyst. Some systems incorporate the capability to manually bias the ammonia injection to account for non-uniformity of NO<sub>x</sub> and flue gas flow at the SCR inlet. Others rely on upstream mixing devices to produce a uniform NO<sub>x</sub> and NH<sub>3</sub> distribution and computerized control systems to maintain the proper ammonia injection rates.



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Ammonia Atomizing Air Compressors - Compressed air is used to atomize the ammonia. Dedicated skid mounted compressors are typically used for ammonia atomization.

Dilution Air Fans - Two 100% capacity dilution air fans shall be provided for each SCR vaporization skid. The fans shall be centrifugal type skid mounted assemblies. For each unit, dilution air fans shall be designed for operation with 350°F to 600°F air, and the capability to withstand 750°F. The fan controls shall have the capability to automatically start the standby fan on low air pressure. The source of dilution air is a takeoff on the air heater air outlet duct. The fans shall be located with each vaporization skid.

Flow Distribution - Flow distribution devices, if necessary, shall be provided to assure adequate flue gas and ammonia distribution and effective utilization of catalyst. The flow at the economizer exit is expected to be stratified and is likely to vary with load. Static and dynamic means of flow compensation may be required.

Electrical Supply - A common electrical supply system provides power to the ammonia pumps and controls. New electrical components will typically be necessary, including an MCC and new switchgear. Alarm/monitoring signals are wired to the nearest existing, continuously manned control room. The increased pressure drop may require that the existing ID fans be upgraded on some units, requiring new electrical connections for larger motors in some cases. The existing starters may be reused, and a new cable will be installed to the motor.

**2.2 Selective Non-Catalytic Reduction (SNCR)**

SNCR was originally developed in Japan in the 1970s for use on oil and gas fired units. SNCR requires injection of ammonia or urea into the proper temperature window within the back pass of the furnace. The ammonia or urea reacts with NOx species to form nitrogen and water. Emission reduction capabilities range from 15-20% at 5-ppm ammonia slip to 30% at 10-ppm ammonia slip in most commercial installations

An SNCR system will require the installation of reagent storage and transfer equipment, a multilevel injection grid and the necessary control instrumentation. Due to the elimination of the catalyst used in the SCR process, the SNCR consumption rates for ammonia or urea are 3-4 times the rates required for an SCR system.

The gas temperature at the point of injection is critical to the NOx reduction performance of an SNCR system. This window falls in a range of 1600-2000°F with an optimum temperature of approximately 1800°F. Above this temperature, ammonia begins to thermally decompose and below this temperature, the reaction rate for NOx reduction decreases, resulting in increased ammonia slip. The temperature profile in any given boiler changes with changes in boiler load. Therefore, the optimum injection point will move during cycling operation and multiple injection points will be required. It should also be noted that the longer the ammonia or urea stays within the optimum temperature window, the higher the NOx reduction that is achieved. Residence times in excess of one second are desirable to achieve the maximum reduction efficiency. The minimum residence time is approximately 0.3 seconds for moderate performance. However, most large utility boilers have heat transfer surfaces (pendants and platens) positioned in this flue gas temperature zone. This will reduce the effective use of the SNCR system, even if multiple injection levels are installed. In some cases, these internal obstructions will make the application of SNCR impractical.

Controlling the injection of the ammonia or urea is critical to performance of the SNCR system. Continuous ammonia slip measurements would allow direct control of the injection rates, but reliable equipment for ammonia measurement is not currently available commercially. The location of the



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injection ports must also consider the distribution of ammonia across the furnace cross section. Multiple injection zones and levels are typically required in a utility application to account for the large volume within a furnace.

One of the major problems associated with ammonia slip is the formation of ammonium bisulfate due to reaction with SO<sub>3</sub> in the flue gas. This compound will precipitate at air heater operating temperatures and can lead to fouling and plugging. Also a concern is the formation of N<sub>2</sub>O during the SNCR reactions. Urea injection typically leads to higher N<sub>2</sub>O production rates. N<sub>2</sub>O formation rates increase as the rate of NO<sub>x</sub> reduction increases.

Additives and enhancers have been tested to improve SNCR performance; none are commercially available. Some are designed to maintain the temperature window (methane) while others are designed to lower the temperature at which the reaction will occur. The use of additives is not considered in the SNCR evaluation.

For SNCR installations, the actual NO<sub>x</sub> removal rate is strongly influenced by the CO level in the injection zone. Variations in the CO concentration can move the temperature window where the urea reaction chemistry performs adequately. Therefore, unit load, burner firing pattern, and localized CO concentration are additional variables that increase the complexity of SNCR system control.

**2.3**     **Hybrid SNCR/SCR**

This system combines the NO<sub>x</sub> reduction capability of SNCR in the boiler with the installation of an SCR catalyst downstream that uses the ammonia slip from the SNCR process. The major problem with this process is adequate distribution of ammonia to the SCR catalyst. Control is difficult due to varying NO<sub>x</sub> distributions in the flue gas. Therefore, inlet NO<sub>x</sub> concentrations at the catalyst face may be much lower than design levels, resulting in ammonia passing through the catalyst unreacted. High local concentrations would have insufficient ammonia for reaction, resulting in reduced NO<sub>x</sub> reduction efficiency. Some hybrid systems will use a supplemental ammonia injection system to ensure sufficient ammonia feed to the SCR catalyst. If the injection system is required, then the cost for the total system will approach that of a full-scale SCR system.

NO<sub>x</sub> reductions typically fall in a range of 50-60% for this hybrid system, although some test programs indicate that up to 90% NO<sub>x</sub> removal is technically feasible with this combined system. The primary reason for including the hybrid design in any evaluation is the potential for cost savings versus a full-scale system. As the ammonia maldistribution increases downstream of the SNCR subsystem, then the volume of catalyst required will also increase. At some point, the cost savings from reduced catalyst volume will be more than offset by the higher chemical feed costs associated with an SNCR system. The purpose of the hybrid design is to increase the SNCR removal efficiency from 30% to 50-60% while at the same time reducing the ammonia slip rates to 5 ppm or less and also reducing the ammonia or urea feed rate by 30% or more. Demonstration tests have shown the potential for this design, but it should not be considered a standard commercial offering.





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### **MERCURY CONTROL TECHNOLOGY DESCRIPTIONS**

- 1.0     Activated Carbon Injection**
- 2.0     Sorbents**
- 3.0     Catalysts**
- 4.0     Fuel Treatments**
- 5.0     Co-Benefit with Wet FGD Systems**

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**1.0 ACTIVATED CARBON INJECTION**

The only Hg control technology that is currently commercially available and previously installed and operated for extended periods at coal-fired utility boilers is the activated carbon injection process. When sorbent injection is combined with a Compact Hybrid Particulate Collector = small Pulse Jet Fabric Filter (COHPAC), the technology has been given the name TOXECON, a system configuration currently patented by the Electric Power Research Institute (EPRI). For this analysis, Washington Group will consider multiple variations on the original TOXECON configuration including sorbent injection upstream of the existing ESP.

**1.1 TOXECON 1 (T1) - Activated Carbon Injection (ACI) with Compact Hybrid Particulate Collector (COHPAC)**

This system has seen the most field-testing and forms the basis for the commercial offering by one vendor. Figure 1-1 provides a flow diagram for the TOXECON 1 system. The major components of the TOXECON 1 design would include a pneumatic transfer system for connection to trucks delivering the activated carbon (AC). The pneumatic piping transfers the AC to the storage silo(s) that are equipped with a vent filter and weigh feeders. The feeders transfer the AC to the pneumatic feed lines that move the AC to the injection location.

An injection grid is fed by a stream splitter that transfers the AC to multiple injection lances feeding the injection grid installed upstream of the new particulate collector. The solids are then collected in a downstream COHPAC FF. This FF will add 8-10" w.g. pressure drop to the flue gas at a typical filtering velocity of 4-6 feet per minute. The filter media collects the AC solids from the flue gas and provides additional contact time for removal of the Hg. The solids are periodically removed from the FF and pneumatically transferred to a separate silo for ultimate loading onto trucks sent to the landfill. In this case, only trace quantities of fly ash would be expected in the AC sent to the landfill. Testing to date indicates that Hg absorbed in AC will not leach out into the groundwater. However, the EPA has not made any formal rulings on the hazards associated with Hg impregnated AC.

This system has shown Hg removal capabilities in excess of 90% when utilizing activated carbons (plain and treated). However, the long-term results show an average of 85% reduction in Hg levels from the inlet flue gas concentration.

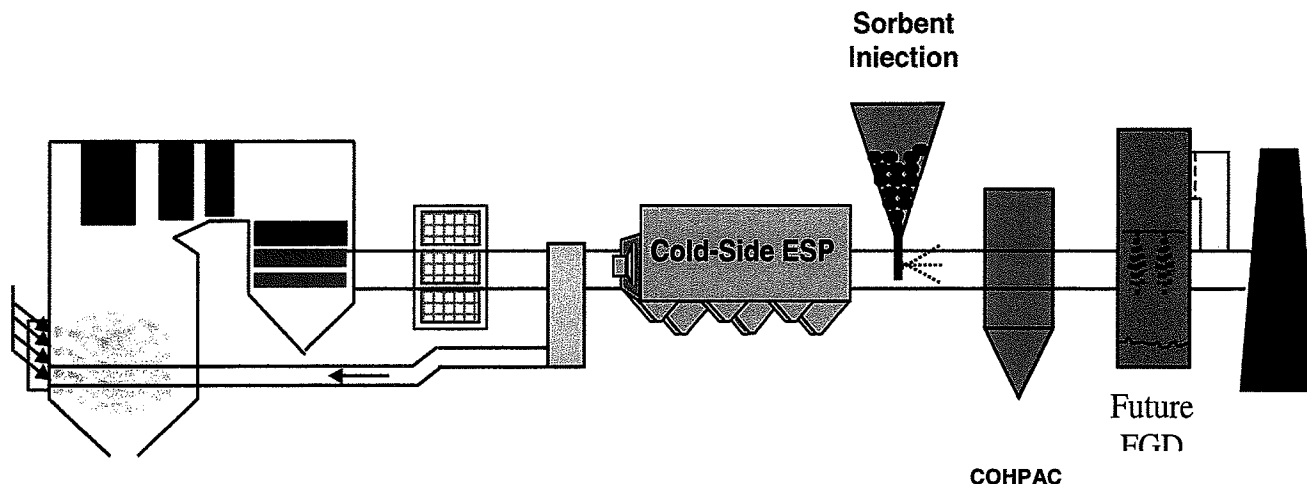


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**Figure D-1.**  
**TOXCON 1 Arrangement**

### 1.2 **TOXCON 1.5 (T1.5) – ACI with ESP Field Conversion to Fabric Filter (FF)**

The T1.5 system will use the same receiving, storage and transport system that is used in the T1 design. In this case, the injection grid will be installed upstream of a PJFF that is installed as a replacement to the last field of the existing ESP. The limited contact time that is available in this configuration will be offset by the use of the PJFF that will act as the gas/solids contacting device. The collection hoppers under the new PJFF will need to be isolated from the existing ESP pneumatic ash handling system so that the ash sales can be maintained. The new pneumatic conveying system will transfer the ash/AC waste solids to a new storage silo, and from there, to trucks for transport to the landfill.

The PJFF retrofit will require that the existing ESP plates in the last field of the ESP be removed, and the last field of the ESP electrically and physically isolated from the rest of the ESP. New fans will be required to provide the air pulsation to clean the bags. A spare module will probably not be included in the design, so that the PJFF will be cleaned on line. The diagram provided in Figures 1-2 and 1-3 show the major components of the TOXCON 1.5 and 2 systems. The only major difference is the fact that in the T1.5 design, the last field of the ESP is replaced with PJFF components. This design will also result in higher power consumption than would be expected in the T2 installation, probably resulting in a 6-8" w.g. pressure drop increase across the particulate collector.

### 1.3 **TOXCON 2 (T2) – ACI into the ESP Upstream of Last Field**

The T2 system has seen limited testing, with one full-scale test completed at the Coal Creek plant, a second test program done at the Pleasant Prairie plant, and a planned DOE/EPRI/ADA-ES test at Entergy's Independence Station scheduled for the latter half of 2005. Mercury removal demonstrated at these facilities was limited to 50-80% at PAC injection rates of 5-10 lbs/MMACF



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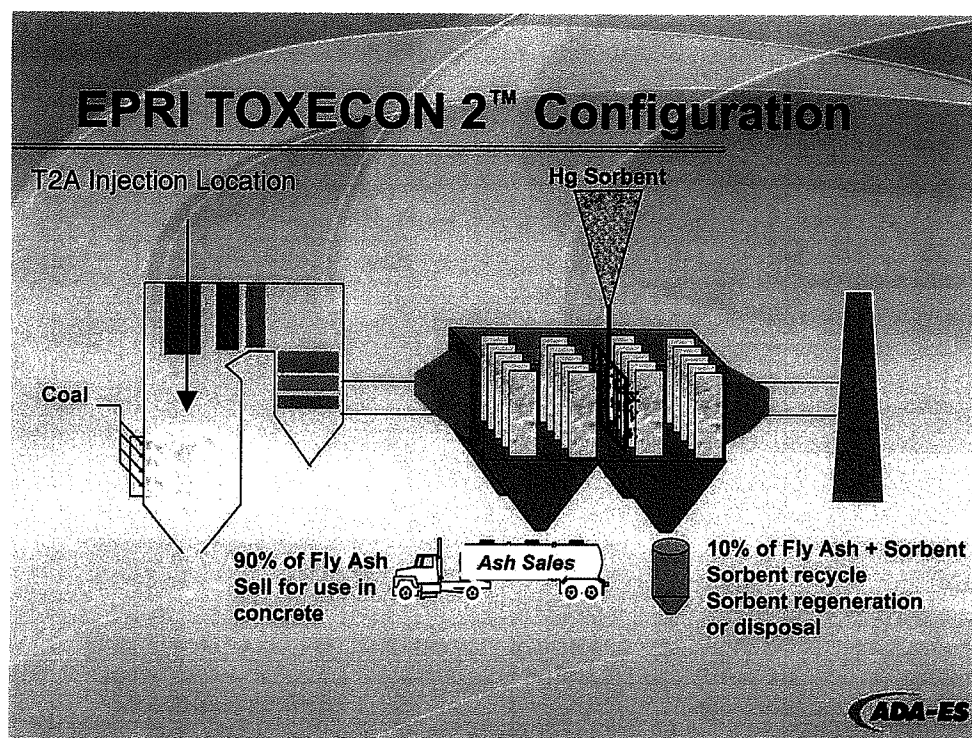
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for cold-side ESPs. This configuration has not been tested on hot-side ESPs. This design will result in significant reductions in the capital investment required when compared to a TOXECON 1 design, but may result in a reduction in the Hg removal efficiency that can be maintained due to the reduced contact time between the AC and the flue gas.

The T2 design could also result in increased particulate emissions due to the increased grain loading to the last field of the ESP. The AC is expected to collect on the ESP plates, and then drop into the collection hopper located under the last section of the ESP. The T2 system will include the same components that were included in the T1 AC receiving, storage and transfer system; however, the equipment will be larger to handle the higher feed rates of sorbent. The injection grid for T2 would be installed just upstream of the last two fields of the ESP.

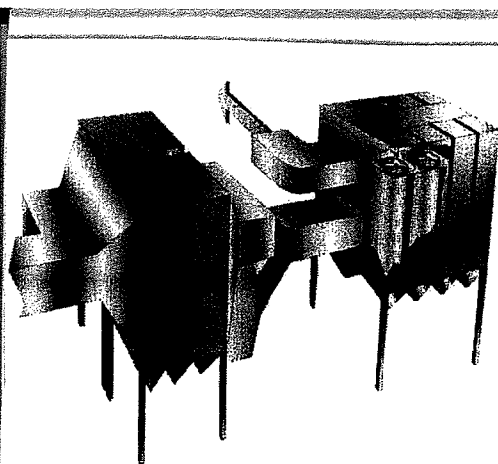


**Figure D-2.**

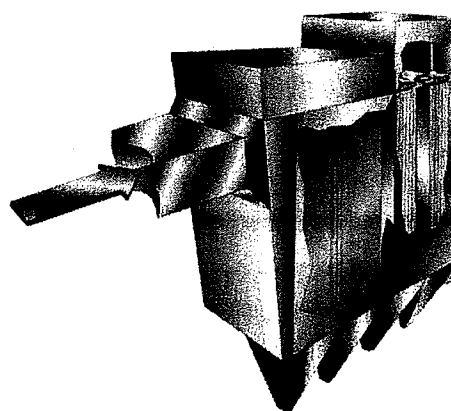
**TOXECON 2 & 2A Flow Diagram (Note: for the TOXECON 1.5 scenario, last field of existing ESP is replaced with a PJFF as shown in Figure 1-3 = COHPAC II scenario)**



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**Figure 1: COHPAC I Arrangement**



**Figure 2: COHPAC II Arrangement**


**Figure D-3**

**TOXECON 1.5/COHPAC II Diagram**

**1.4 TOXECON 2A (T2A) – ACI into the Ductwork upstream of the ESP**

The T2A system has been tested at full-scale on a number of units. Mercury removal demonstrated at these facilities varied from 50 to 80% at AC injection rates of 5-10 lbs/MMACF but limited field tests have shown up to 90% removal with BPAC at injection rates of 3-5 lbs/MMACF for cold-side ESPs. Limited test results from hot-side ESPs utilizing HPAC have shown Hg removal rates of 50-65%. This design will also result in significant reductions in the capital investment required when compared to a TOXECON 1 design, but may result in a reduction in the Hg removal efficiency that can be maintained due to the reduced contact time between the AC and the flue gas.

The T2A design could also result in increased particulate emissions due to the increased grain loading to the ESP and the potential for reentrainment of AC particles. The AC is expected to collect on the ESP plates, and then drop into the collection hoppers located under the ESP. This arrangement will prevent the sale of fly ash due to the increased carbon content. The T2A system will include the same components that were included in the T1 AC receiving, storage and transfer system; however, the equipment will be larger to handle the higher feed rates of sorbent. The injection grid for T2A would be installed in the ductwork upstream of the ESP.

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### 2.0 SORBENTS

Sorbents that have been used in previous mercury control demonstration projects include activated carbons (both plain and treated) and Amended Silicates. All three sorbents have test data showing 50-90% mercury removal with injection rates ranging from 2-10 lb/MMacf. Figure 4-4 shows the mercury removal efficiency for plain AC and treated AC during tests conducted at the Holcomb and Stanton stations. The three sorbents options are described in the following sections.

#### 2.1 Plain Activated Carbon

Plain (untreated) activated carbon is commercially available from multiple suppliers for an average price of \$0.50 per lb. This is the only system on the market today that has been demonstrated on multiple full-scale installations on a variety of coals and for extended test periods. These activated carbons are capable of achieving 90% mercury removal with a fabric filter, but at injection rates sometimes approaching 10 lb/MMacf. Performance varies between the carbon suppliers. The injection of AC will also contaminate the flyash unless the ash is removed upstream of the injection grid; this can make the fly ash unmarketable for some applications.

Plain activated carbon is commercially available from multiple sources both domestically and internationally. This type of activated carbon is mass-produced for commercial applications other than mercury control from coal fired power plants.

#### 2.2 Halogenated Activated Carbon

Treated activated carbons are produced by adding bromine, iodine or fluorine to the carbon to increase its ability to capture mercury. Field testing with halogenated activated carbons indicates that they can achieve 90+% mercury removal at injection rates of 2 lbs/MMacf or less. The trade off is that treated activated carbons currently cost \$1-2 per lb, but with increased production capacity, the price of HAC is projected to drop to \$0.75/pound.

Sorbent names include BPAC from Sorbent Technologies and Darco Hg-LH from Norit Americas, both treated with Bromine. Sorbent Technologies is also developing an AC sorbent that will have little to no effect on concrete production (CPAC).

#### 2.3 High Temperature Carbons

High temperature carbons are under development by Sorbent Technologies and Norit. These carbons are being developed specifically to operate at hot-side ESP temperatures. These materials are not commercially available yet but development work is continuing.

Test results for HPAC have shown Hg removal efficiencies of 55-65%. HPAC from Sorbent Technologies is the only high temperature carbon that has publicly available test results.

#### 2.4 Amended Silicates™

Amended Silicates™ is a patented product only available through Amended Silicates LLC, a joint venture between ADA Technologies and CH2M Hill. The Amended Silicate sorbent uses silicate materials (potentially heat and pressure treated fly ash) as substrate particles that are impregnated with chemicals that have a strong affinity for mercury. No full-scale tests of the amended silicate sorbent have been conducted to date, but extensive pilot plant data has been collected. The reported mercury removal rates and sorbent injection rates are similar to AC with mercury removal ranging from 50-96% at injection rates of 1.6-9.0 lbs/MMacf. Amended Silicates LLC has reported that due to the silicate content of the base



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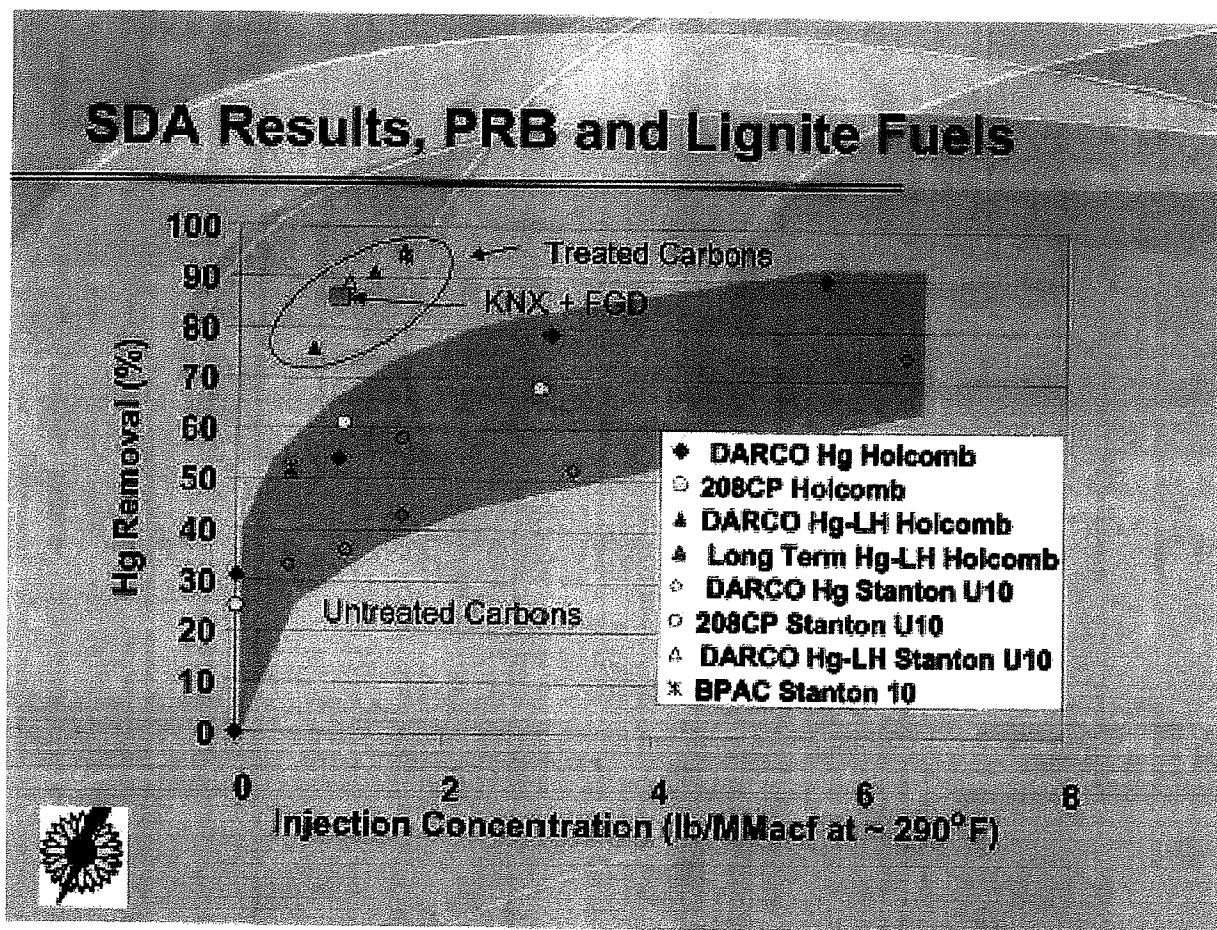
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material, the flyash/Amended Silicate mixture can still be sold as a concrete additive. Amended Silicates LLC has estimated that they will sell the product for \$0.45-0.55 per lb.

Amended Silicates™ is only produced by Amended Silicates LLC and full-scale production has not begun. This material is only applicable to mercury control from coal-fired power plants.

### 2.5 Published Sorbent Injection Test Data

Test results from the various field trials of the Hg control technologies and sorbents described above are summarized in Table D-1. The U.S. Department of Energy's National Energy Technology Laboratory (DOE/NETL) and Electric Power Research Institute (EPRI) have been funding and supporting these fields tests. Phase II field testing is scheduled through 2007. The goal of this program are to develop technologies that can achieve 50-70% reductions ready for commercial demonstration by 2007, and systems for 90% reductions ready for commercial demonstration by 2010.



**Figure D-4.**  
**Activated Carbon Performance (Treated & Untreated Products)**



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**Table D-1**

**Mercury Emission Control Technologies Test Results**


<b>TOXECON Configuration.</b>	<b>Plant Name</b>	<b>Coal Type</b>	<b>Controls</b>	<b>Project Scale</b>	<b>Sorbent Type</b>	<b>Removal (%)</b>	<b>Feed Rate (lb/MMACF)</b>
2A	Meramac	Subbituminous	CS-ESP	Full Scale	PAC	70	10+
2A	Pleasant Prairie	Subbituminous	CS-ESP	Full Scale	PAC	60	10+
2A	Brayton Point	Low S Bituminous	CS-ESP	Full Scale	PAC	80	20
2A	Salem Harbor	Low S Bituminous	CS-ESP	Full Scale	PAC	90	10
2	Coal Creek	Lignite	CS-ESP	Full Scale	PAC	75	10+
2A	Leland Olds	Lignite	CS-ESP	Full Scale	PAC	65	10
2A	Pleasant Prairie	Subbituminous	CS-ESP	Slipstream	B-PAC	89	4.9
2A	Lausche	High S Bituminous	CS-ESP	Full Scale	B-PAC	70	4.0
2A	Cliffside	Low S Bituminous	HS-ESP	Full Scale	B-PAC	80	6.4
2A	St. Clair	Subbituminous Blend	CS-ESP	Full Scale	B-PAC	90	3.0
2A	St. Clair	Subbituminous	CS-ESP	Full Scale	B-PAC	90	3.0
Note 1	Stanton	Lignite	SDA only	Full Scale	B-PAC	70	1.5
Note 2	Holcomb	Subbituminous	SD/FF	Slipstream	B-PAC	82	1.8
Note 2	Stanton	Lignite	SD/FF	Full Scale	B-PAC	95	1.5
1	Valley	Low S Bituminous	FF	Slipstream	B-PAC	94	0.5
1	Pleasant Prairie	Subbituminous	FF	Slipstream	B-PAC	87	0.5
1	E.C. Gaston	Low S Bituminous	COHPAC	Full Scale	PAC	90	3
1	Comanche	Subbituminous	FF	Slipstream	AS	96	9
Note 3	Holcomb	Subbituminous /Bituminous Blend	SD/FF	Full Scale	----	80	15% western Bituminous fuel

Note 1 – Test was conducted across the SDA only.

Note 2 – Test was conducted across SDA/FF arrangement.

Note 3 – No Sorbent Injection - Test was to determine effect on Hg removal from blending Western bituminous coal with subbituminous coal.



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### 3.0 CATALYSTS

#### 3.1 Low Temperature Catalysts

This concept involves oxidizing elemental Hg across a catalyst and then capturing the oxidized Hg by conventional SO<sub>2</sub> control devices. The catalysts under development are similar to standard honeycomb SCR catalyst and a sample of a single catalyst block is shown in Figure D-5.

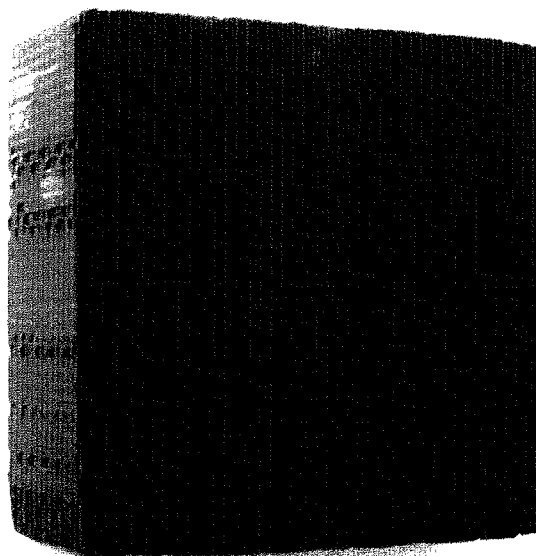


Figure D-5

Hg Oxidation Catalyst Block

Pilot scale tests of this technology have been conducted at three sites and with a number of different catalysts. The tests have shown that the catalysts are capable of oxidizing up to 84% of the elemental Hg entering the catalyst. There is the potential for Hg re-emission in the FGD system. Additional testing is being done on FGD additives to limit Hg re-emission.

Testing has also indicated that catalyst installed in horizontal ductwork will require cleaning to prevent catalyst pluggage. Sonic horns have been used successfully on the pilot plants for this purpose. The pressure drop across the catalyst is typically less than 0.5" H<sub>2</sub>O per layer.

The balance of plant impacts for this technology are potential draft system impacts due to the added pressure drop from the catalyst, space constraints for locating a separate casing for the catalyst or installation in existing ductwork which would require additional structural steel for support of the catalyst and a means of removing the accumulated flyash from the catalyst and associated ductwork.

There are no commercial or demonstration scale installations of this technology but further test work is scheduled.



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**MERCURY CONTROL TECHNOLOGY DESCRIPTIONS**

**3.2**     **High Temperature Catalysts**

Units equipped with SCR and wet FGD have shown higher levels of Hg removal across the system than those equipped with only wet FGD. This is due to the increased oxidation of elemental Hg across the SCR catalyst. The level of oxidation is dependent upon the chlorine level of the coal. Research is being conducted into high temperature Hg catalyst and SCR catalyst with improved Hg oxidation potential.

Since SRP has ruled out the installation of SCR at CGS this is not a viable option.

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**MERCURY CONTROL TECHNOLOGY DESCRIPTIONS****4.0 FUEL TREATMENTS****4.1 Coal Chemical Pre-treatment**

Testing is being conducted into the use of chemical additives to increase Hg oxidation and therefore enhance Hg capture in wet FGD systems. These tests are primarily being conducted at lignite-fired plants but the theory can be applied to other fuels. For the current testing, the additive is injected into the coal pipes leading to the furnace. Preliminary test reports from short term testing have shown up to a 44% reduction in Hg emissions. This is an on-going test program.

**4.2 Coal Blending**

Tests at Holcomb Station showed that raising the chloride content of the coal through blending higher chloride coal with a low chloride coal can increase the Hg removal rate across a Spray Dryer / Fabric Filter pollution control system. Hg in flue gas at plants burning coals with higher chlorine content, such as Eastern bituminous coals, appears mostly in the oxidized state, which is removable by conventional FGD systems. The tests at Holcomb blended approximately 15% higher chloride coal with the plants PRB coal by dumping coal from a front-end loader onto incoming railroad cars before they were unloaded.

This approach resulted in 80% Hg removal across the SD/FF at Holcomb Station. Further testing of this concept is planned at Detroit Edison's Monroe Station, which burns a wide variety of coals and has an extensive coal blending system installed at the station.

Implementing this strategy on a full time basis could require extensive upgrades to the coal handling system to accommodate fuel blending and would require an analysis of boiler operational impacts.

**4.3 Coal Preheating / Hg Collection**

Removal of Hg from the coal prior to delivery to the site is an option that is nearing commercial availability. The K-Fuel™ Process exposes the raw coal to 400-500oF temperatures at 400-500 psi to expel moisture from the coal and reduces the Hg emissions from the coal. Published data, from KFx Inc. (owner of the K-Fuel™ Process), shows a 70% reduction in Hg content from the raw coal to the K-Fuel™ product.

This option would result in the reduction of Hg emissions from the plant without making any modifications to the air pollution control equipment installed at the plant. The change in fuel characteristics may require coal handling/coal processing/boiler upgrades or operational changes to accommodate the K-Fuel™ product. These would need to be evaluated on a case-by-case basis.



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**5.0 CO-BENEFIT WITH WET FGD SYSTEMS**

**5.1 Oxidizing Chemical or Gas Injection Upstream of FGD**


This concept involves oxidizing elemental Hg with small amounts of a halogen injected into the boiler and then capturing the oxidized Hg by conventional SO<sub>2</sub> control devices. The presence of chlorine promotes the oxidation of Hg, and oxidized Hg is readily removed across a wet FGD system. Calcium chloride and calcium bromide injection into the furnace have been tested on a limited scale on plants burning PRB and North Dakota and Texas lignites.

The test results to date have and increase in the Hg removal across the FGD systems from a baseline of 45-55% to 73-81% with halogen injection. Testing to date has been for short durations and long-term balance-of-plant impacts have not been determined. Further testing is planned and EPRI is looking for expanded project participation.

**5.2 Chemical Additives to Control Hg Reemission from FGD Slurry**

Testing is being conducted to evaluate the use of additives in wet lime or limestone FGD systems to prevent oxidized Hg from being reduced and subsequently re-emitted from the FGD absorber as elemental Hg. Reducing or eliminating the amount of Hg that is reemitted from the FGD system will increase the overall collection efficiency of the system.


Testing is being conducted at three sites that burn: 1) Texas lignite, 2) a low-sulfur bituminous coal, and 3) a high-sulfur bituminous coal. There are no test results to report at this time.

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**APPENDIX – E**


**IECCOST MODEL RUN SUMMARIES BY PLANT**

1. SUMMARY OF BASELINE INPUT DATA FOR IECCOST MODELS
2. EMISSION CONTROL EQUIPMENT COST AND DESIGN SUMMARY
3. COLUMBIA 1 & 2
4. EDGEWATER 4 & 5
5. NELSON DEWEY 1 & 2

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## APPENDIX – F

### CLIENT/VENDOR COST INFORMATION

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**APPENDIX – G**

**COMPLIANCE MODEL RUN SUMMARIES**



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## APPENDIX – H

### GENERAL ARRANGEMENTS OF SCR & LSFO FGD TECHNOLOGIES, BY PLANT

1. COLUMBIA 1 & 2
2. EDGEWATER 4 & 5
3. NELSON DEWEY 1 & 2